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Impacts of Environmental Regulation and Wind Penetration Level on The ERCOT Market

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Impacts of Environmental Regulation and Wind Penetration Level on The ERCOT Market

by

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THESIS

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Dedicated to Songa and John.

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Impacts of Environmental Regulation and Wind Penetration Level on The ERCOT Market

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The University of Texas at Austin, 2012

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Abstract

As more renewable resources are added into the grid and environmental regulations are imposed to reduce emissions, there will be dramatic changes in the generation portfolio. Assessing the impact of these changes is important for policy makers, market participants, and general public to understand trends in the electricity market. This paper addresses this issue by analyzing how the ERCOT market is affected by CO_2 penalty and wind penetration. In order to assess the future power system, the study model should represent the long term dynamics of various factors to find out how investment decisions are made economically in a competitive market with appropriate assumptions. Another important aspect is the short term market dynamics from real operation of power system. For this study, AURORAxmp, a commercially available market simulator, is utilized to capture both long term and short term dynamics. This study runs 5 different scenarios: two base cases with and without CO_2 price, 20%, 27%, and 33% wind penetration level. The result shows that, increasing wind penetration reduces production and capacity of both coal and gas units, electricity market prices, and amount of emissions. However, increasing wind penetration has greater impacts on a decrease in generation from thermal units than reduction in

thermal capacity, resulting in 11.4 % capacity value of wind power. The study also confirms that CO_2 price impacts capacity and generation of coal (negatively) and gas (positively) units in opposite ways, and reduces emission, but increases power prices and generation cost. Especially, the impact on retirement of coal units is noticeable. Almost half of the current coal capacity (19 GW), 9,390 MW, is retired by 2040 in this study.

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Introduction

1.1 Background

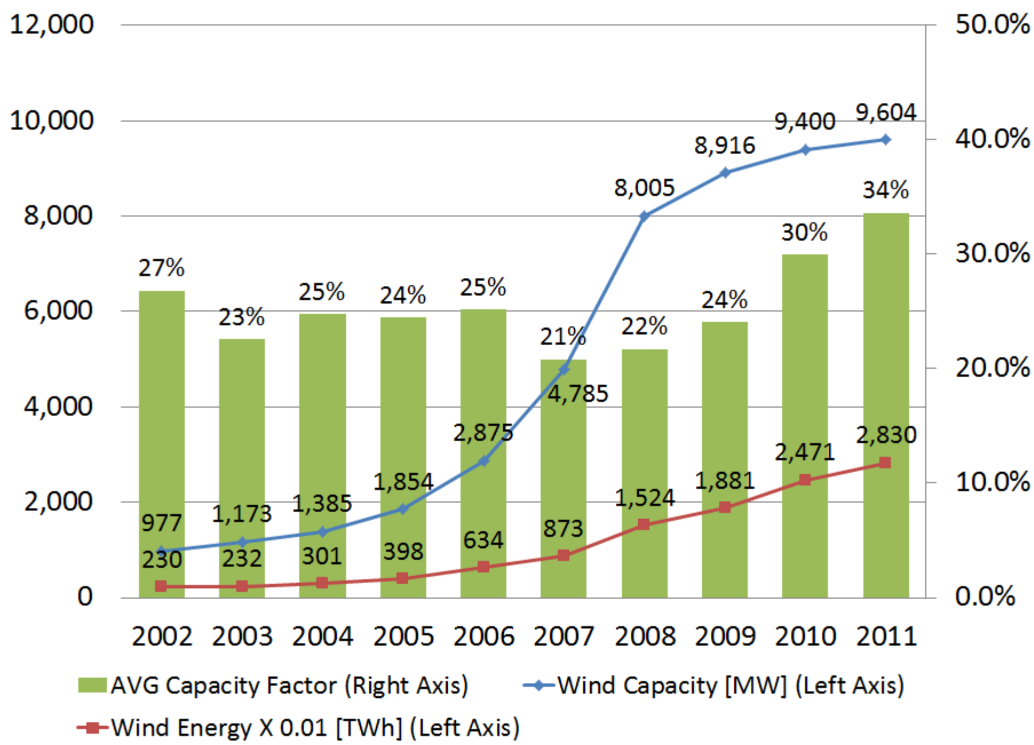
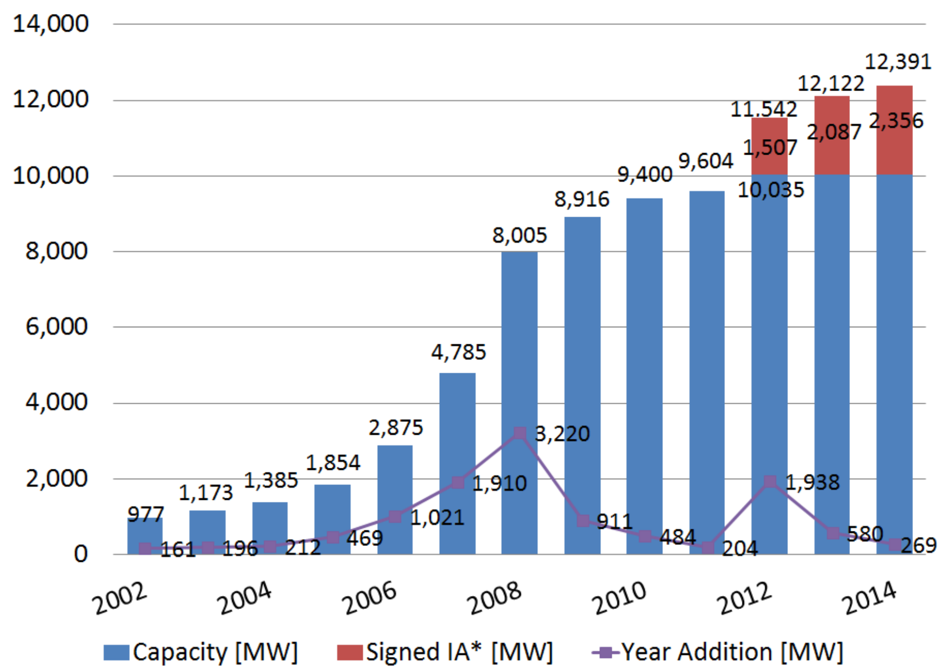


Figure 1.1: Wind Capacity, Energy, and Capacity Factor in ERCOT [8]

Wind resources have been added into the Electric Reliability Council of Texas (ERCOT) grid rapidly since the mid-2000s (Figures 1.1 and 1.2). The investment decision to build wind farms in ERCOT was supported by Federal tax incentives, either the Investment Tax Credit (ITC) or Production Tax Credit (PTC). Those incentives parallel world-wide efforts to reduce Green House Gas (GHG) emissions by



IA*: Interconnection Agreement

Figure 1.2: Wind Capacity Addition by Year in ERCOT [15]

generating electricity more from renewable resources like wind, solar, biomass, etc.

However, intermittency of renewable sources results in a number of operational and planning challenges to the Independent System Operator (ISO). For example, the ISO should decide the short-term / long-term forecast methodology for renewable energy production, the appropriate amount of ancillary services [2], ramping capability of the system, cost-effective transmission planning to deliver renewable energy, etc.

Besides, with current high uncertainty in renewable policies and environmental regulation, it is difficult for market participants to make long term investment decisions. This is because the future generation portfolio can vary significantly depending on the timing and magnitude of these rules.

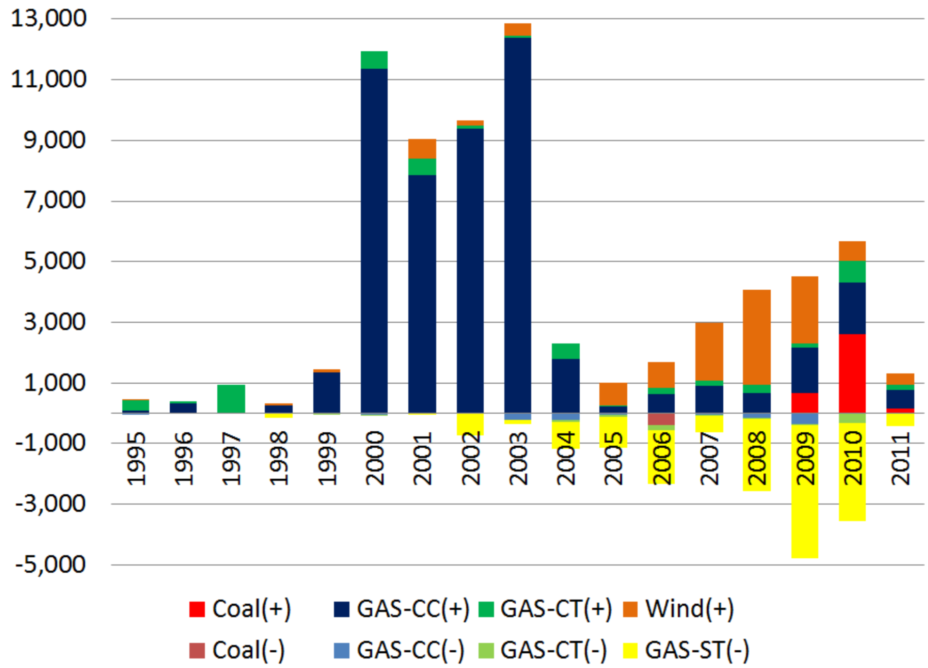
The purpose of this study is to address the second issue: assessing the impact of wind penetration level and CO_2 price on ERCOT capacity expansion, generation by fuel type, market price, and amount of emissions. Because marginal cost of wind energy production is essentially zero and even negative considering tax incentives [1], having more wind will result in reduced production of both gas and coal units by economic dispatch logic.

However, there are other factors that should be taken into account. As having more renewables and corresponding uncertainty in future production, thermal units would be procured and deployed more as forms of ancillary services. Another factor is that electricity demand is growing along with peak demand. ERCOT projects that its demand growth is expected to continue for a next decade with moderate rates [11]. Therefore, in order to serve increasing demand and to deal with intermittency of renewable resources with a certain level of reliability, ERCOT needs conventional thermal generation built in the future as well.

How much and what type of units are going to be built or retired in a deregulated market is solely decided by profitability of a unit and difficult to be answered due to high uncertainty in the market. The decision is affected by various factors such as, but not limited to, overall economic situation, population and GDP growth, electricity demand growth, fuel price projection, environmental regulation, renewable energy policies, capital expenditure (CAPEX) for new generators, demand side management and energy efficiency improvement, regulatory uncertainty, etc.

Especially, environmental regulations and renewable incentives leave significant challenges to investors, policy-makers, and market participants to understand future trends in an electricity market. Since they will lead to different renewable energy penetrations, they will result in dramatic changes in an electricity market: power prices, capacity addition and retirement, fuel consumption and amount of emissions, and other market results will also be changed. Therefore, it is important to assess the impacts of these policies on an electricity market in order to determine appropriate policies for the desired future of a power market.

1.2 Past and Current ERCOT Market



CC: Combined Cycle, CT: Combustion Turbine, ST: Steam Turbine

Figure 1.3: Capacity Addition (+) and Retirement (−) [MW] by Fuel Type in ERCOT [5] and [20]

Figures 1.2 and 1.3 show historical capacity expansion for wind and the whole of ERCOT respectively. The ERCOT system has no major interconnections to other systems, so most demand should be served by generation in ERCOT. So far the ERCOT market has been successful at inducing new generation capacity into the market. In Figure 1.3, the capacity *boom* between 2000 and 2003 was led by combined cycle units which were added to take an advantage of deregulation and high efficiency [20]. After that, from 2005 to 2010, wind addition increased significantly every year thanks to favorable policies for renewable energy. Furthermore, total $15,700$ MW of gas steam turbine units were retired between 1998 and 2011. In short, ERCOT is

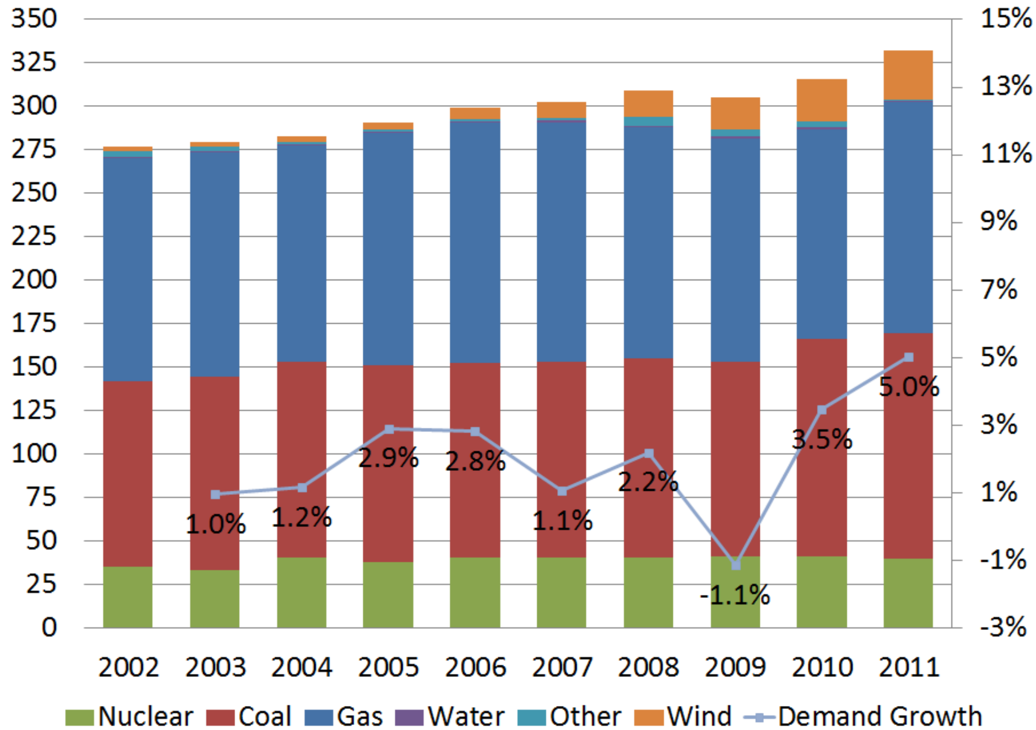


Figure 1.4: Energy(TWh) by Fuel Type and Demand Growth Rate [8]

an energy-only market with higher penetration of both efficient combined cycle and intermittent wind.

Figure 1.4 shows annual generation by fuel type and growth rate of ERCOT demand from 2002 to 2011. Except for the year of economic recession in 2009, the ERCOT total demand has increased at rates from 1% to 5%. The recent dramatic increase in demand – 5% is due to unprecedented drought and hot summer in 2011, which also resulted in the record high peak demand (68,379 MW) and annual demand (334 TWh) [11]. Coal generation produces approximately 38 % of annual generation, while gas generation produces 45 % historically as shown in Figure 1.5.

Because gas units are marginal for most settlements, the ERCOT market is highly affected by natural gas prices. Besides, wind and nuclear units are dispatched first by the economic dispatch logic, so the coal and natural gas units compete with

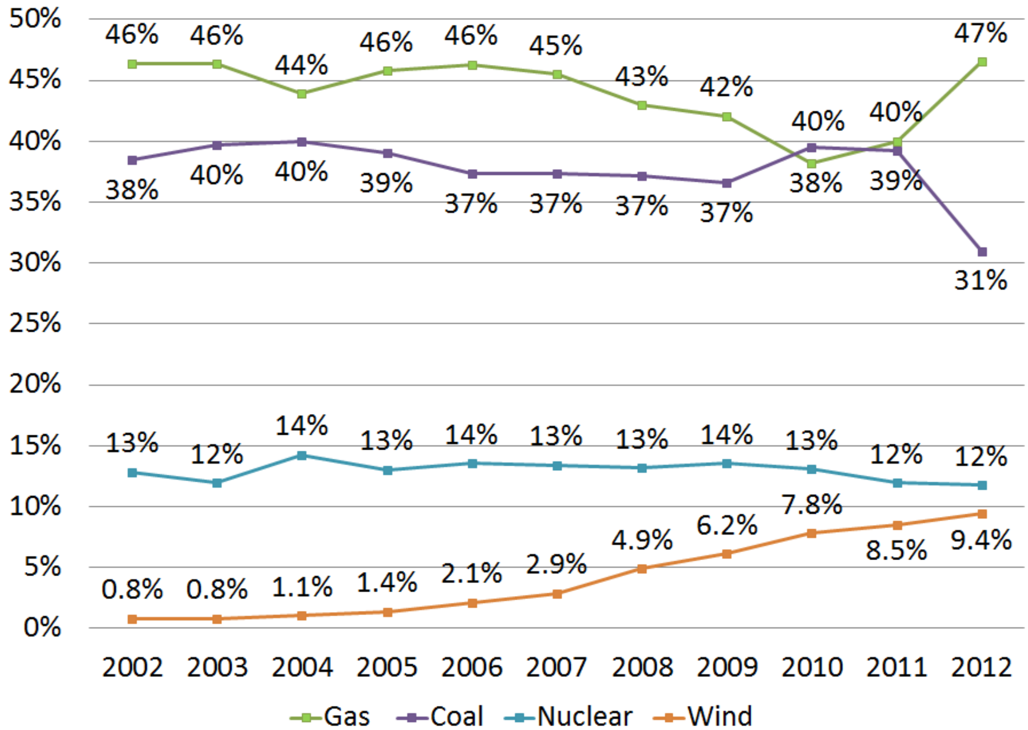


Figure 1.5: Energy Penetration by Fuel Type[8]

each other for the rest of the load. Negative correlation between coal and gas electricity production is evident in Figure 1.5. Another negative correlation between gas price and gas penetration level except when affected by outside impacts is shown in Figure 1.6. Recent increase in gas and decrease in coal penetration have resulted from significant amount of shale gas production and corresponding low gas prices. Once gas prices goes below 3.5 $\$/mmbtu$, generation conversion from coal to gas is accelerated and accounts for the highest penetration level of gas and lowest penetration of coal units in 2012.

Recently, resource adequacy has become an urgent issue in ERCOT. Last year, exceptional drought and high temperature have threatened ERCOT several times to shed load, even though this worst situation of load shedding has not happened. In 2011, the realized reserve margin of 9.6% was significantly below the planning reserve

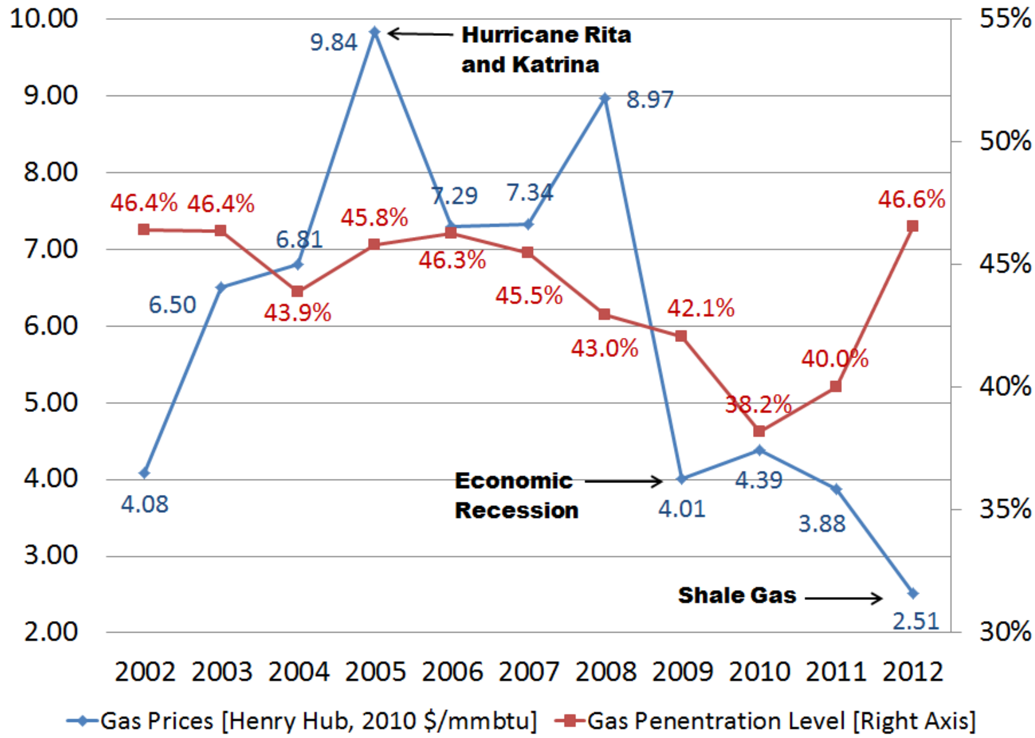


Figure 1.6: Gas Prices and Gas Penetration Level [8], [17]

margin of 13.75% [20]. ERCOT defines a reserve margin as follows [14]:

$$\text{Reserve Margin}[\%] = \frac{\text{Firm Load Forecast [MW]}}{\text{Resource Capacity [MW]}} \text{ where}$$

- Firm Load Forecast = Summer Peak Demand − LAARs[1] as Responsive Reserve − Emergency Interruptible Load Services − Energy Efficiency Reduction

- Resource Capacity = Installed Capacity without Wind + Capacity from Private Network + ELCC[2](8.7%) of Wind + RMR[3] Units + 50% of DC Ties + Switchable Units + Planned (Signed IA[4] and Air Permits) Units

LAARs[1]: Load Acting As Resources

ELCC[2]: Effective Load Carrying Capability

RMR[3]: Reliability Must Run

IA[4]: Interconnection Agreement

However, the problem is that current market design and surrounding conditions does not seem to resolve this issue in the near future unless major changes both inside and outside of the ERCOT market occur. The first reason is attributed to recent development and massive reserve estimation of shale gas in North America. Abundant gas production from shale reduces gas prices, and this year's gas price (in 2010 real dollar) is the lowest in the last 10 years (Figure 1.6). High gas production level and resulting low gas prices is expected to continue for the next several years. Since, in peak hours of ERCOT, mostly gas units are marginal and setting a market price, low gas price reduces power price, which is good for a customer. But from generation investor perspectives, low gas prices and corresponding low power prices may not give enough revenue forecast for them to invest in new generation capacity.

The second reason is related to a fundamental structure of an electricity market: how much is an appropriate offer-cap to induce new entries so that total capacity can satisfy a desirable reserve margin? A price offer-cap in an energy-only market is usually higher than that in the markets with a capacity market structure like PJM, since in an energy-only market, the offer cap determines capacity profits of entire generation fleet, while a market with a capacity market structure separately remunerates capacity investment. The current issue leads market participants, ERCOT, and the Public Utility Commission to be concerned as to whether the ERCOT energy-only market can induce new generation capacity to the level that satisfies the planned reserve margin, 13.75%. As a part of the remedies, ERCOT increased its price offer cap by 50% from 3,000 $/MWh to 4,500 $/MWh, effective on Aug. 1st, 2012, and additional increase up to 9,000 $/MWh is under discussion now.

As wind capacity adds every year, its penetration level also increases steadily and shows currently 9.42% this year with approximately 10,000 MW capacity in

Figure 1.5. Future wind projects after 2012 highly depends on whether PTCs are extended. Another important impact is the completion of CREZ transmission upgrades by 2014. The upgrade is expected to expand transmission transfer capability to support an additional approximately 10 GW of wind potential across ERCOT and Panhandle area [7].

1.3 Contribution of the Thesis

This study assesses the impact of different wind power penetration and environmental regulations on the ERCOT market fundamentals: types and amount of capacity addition and retirement, generation by fuel type, market clearing prices, amount of emissions. They are important values for policy maker and general public to see general trends of Future of the ERCOT market depending on different wind penetration levels and environmental regulation. Furthermore, it also provides pivotal information for market participants and investors to make decisions on future strategies, asset management, investment, risks, etc.

There is still a great deal of uncertainty regarding reasons for climate change and necessary environmental regulations. However, there is a consensus that we need to generate electricity in cleaner ways. The questions that should be answered are how much electricity should be produced by renewable resources, what is the impact of cleaner electricity on a power market, and how much reduction of CO_2 emission is expected from different penetration levels of renewable resources. This study is expected to answer not all, but some of these questions and enhance understanding the impacts of environmental regulation and wind penetration levels on the ERCOT market and emission reduction in long-term perspectives.

1.4 Outline of the Thesis

The paper has started with the overview of ERCOT market in the previous section. It explained historical expansion and current issues in ERCOT. Following will describe the study methodology and discuss factors needed to appropriately represent short term and long term characteristics of power markets. Assumptions in this study will be delineated next. After that, it shows the main results and indication from simulations of five different scenarios. The result chapter consists of two sections: The impacts of environmental regulation and that of wind penetration. The last section will conclude this study and suggest further studies.

Note that in this paper, penetration level of a fuel type is defined in terms of energy. For instance, total wind energy generated in 2011 is 28 TWh, while ERCOT total generation is 331 TWh at the same year. In this case, wind penetration level is $28/331 = 8.5\%$, which can also be verified in Figure 1.5.

Chapter 2

Methodology

2.1 Introduction

This section discusses the methodology that is applied in the paper and factors that should be represented appropriately to address issues raised in the previous section. There are a lot of dynamics in daily operation of power system as well as longer term investment decisions. Therefore, developing the right methodology is critical to analyze future of a electricity market and provide meaningful results. Section 2.2 will explains short- and long-term dynamics of a power market and delineate the capacity expansion logic that is used in this thesis.

2.2 Market Dynamics

As [19] describes, in order to study the impacts of renewable resources on electricity market from a long term perspective, one should capture both short-term and long-term dynamics of the market. In details, the short term dynamics mean that the model should properly represent operational limits, flexibility and variability of resources at least with hourly resolution. The operational limits that should be modeled are: ramp up or down limits, minimum up-time or down-time, minimum and maximum capacity, average heat rate, heat rate at minimum, wind and solar profiles of a region, Variable Operation and Maintenance (VOM) cost, Fixed Operational and Maintenance (FOM) cost, start-up cost, etc. They are required for the purpose of making unit commitment and optimal dispatch decisions, so as to depict daily and hourly operation of power system and electricity market as closely as possible to reality.

For long-term dynamics, the model should be able to make economic investment decisions for which type of unit to be added to or retired from the current market based on long term market assumptions such as forecasts of fuel prices, demand growth, inflation, CO_2 prices, CAPEX variation, transmission upgrades etc.

There are publicly and commercially available market simulators which incorporate the above characteristics at different levels; National Energy Modeling System (NEMS) [4], Renewable Energy Deployment System [24] are developed by EIA and National Renewable Energy Laboratory (NREL) respectively. PLEXOS, UPLAN, AURORAxmp are examples of commercially available market simulators described in [16]. This paper utilizes the long term capacity expansion functionality of AURORAxmp.

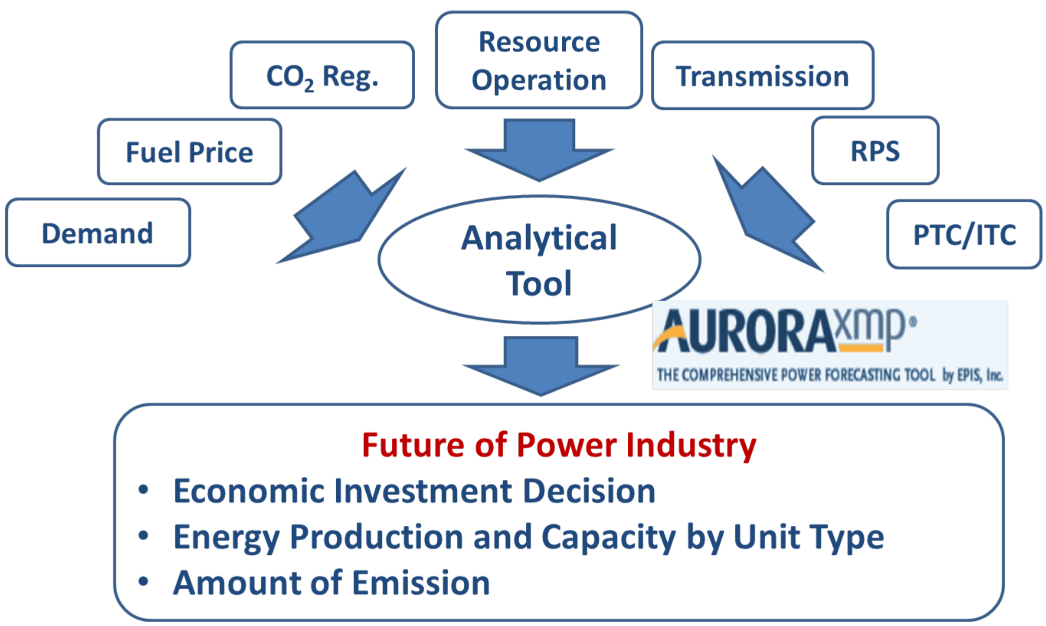


Figure 2.1: Inputs and Outputs of AURORAxmp [6]

The model represents operational characteristics of all ERCOT resources in detail. As a result, it covers short term market dynamics described above. Its long term optimization logic decides economic investments (addition and retirement of a unit) by comparing real *Levelized Net Present Value* (Levelized NPV) of each existing and candidate units. After that, the model decides an existing unit's stay or retirement as well as a candidate unit's addition. It assumes that all investment decision is made economically in a competitive market. It means that all market participants invest or retire their assets solely based on a unit's profitability (NPV in the model). Figure 2.2 shows the logic flows of the long term investment decision in the model.

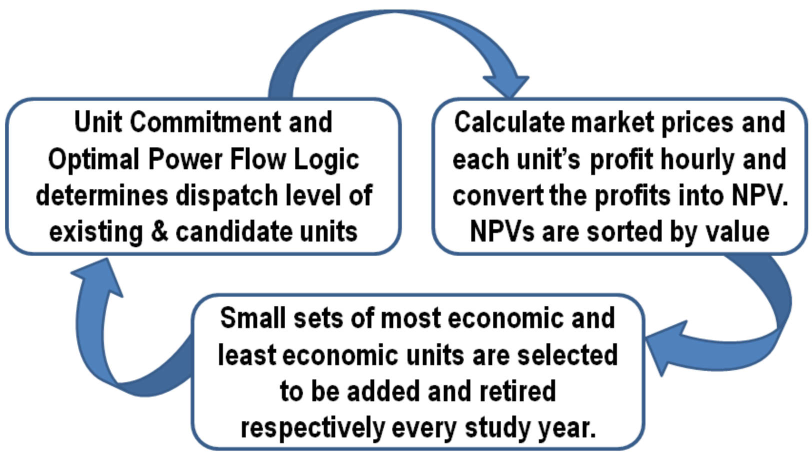


Figure 2.2: AURORAxmp Long-Term Optimization Logic [6]

Before starting the iterative optimization processes as described in Figure 2.2, a user determines specifications of candidate units: unit types, their capacities and capital costs, maximum number of units that can be built in each year and during the overall study period, begin (or end) year when a unit is included (or excluded) in a candidate unit list, etc. After that, the model enumerates candidate units every year. Existing units and candidate units are dispatched by the Unit Commitment (UC) and Optimal Power Flow (OPF) logic. It is the start of the first iteration.

Hourly zonal prices are generated in each study year by UC and OPF logic.

It enables the model to calculate each unit's profit every hour and every year. Profits are calculated as follows,

$$\text{Profit} = \text{Total Revenue} - \text{Total Cost}$$

- Total Revenue = Energy Revenue + Reserve Revenue
- Total Cost = Fuel Cost + Start-Up Cost + VOM + FOM + Emission Cost

Then, profits are converted into Present Value by discounting cash flow calculation. Each unit's NPV calculation also includes capital cost of the unit. NPV of a unit is divided by its capacity and yields Levelized NPV.

$$\text{Levelized NPV} = \frac{\sum_{i=1}^{N} \frac{\pi_i}{(1+r)^i}}{\text{Capacity [MW]}} \text{ where} \tag{2.1}$$

N = study period or at least 20 years, π_i = Profit in the i^{th} year, r = discount rate

Each unit's Levelized NPV is sorted by value. A small set of most profitable units in a candidate unit group is added, while a small set of least profitable units in an existing unit group is retired. This is the end of the first iteration and the process is repeated until the model satisfies following condition:

If the number of iteration reaches the minimum, check two criteria:

- Whether the system average price difference between this iteration and the previous iteration falls within the threshold, or
- Whether the iteration reaches its maximum number

The profitable range in Figure 2.3 varies by iteration, but as the iteration goes toward the end, the variation reduces and the range converges to the optimal set of units.

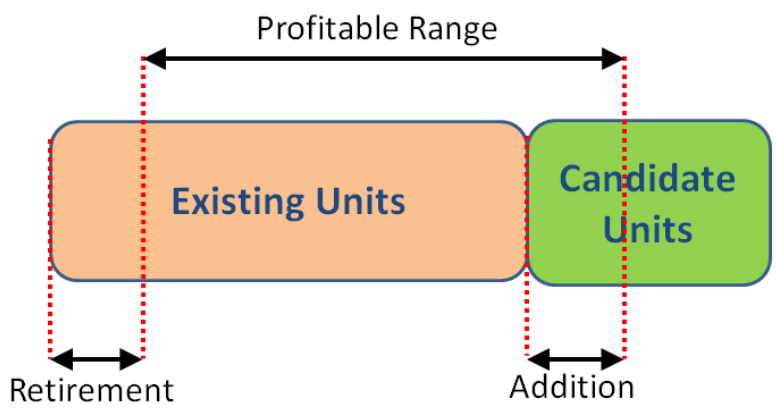


Figure 2.3: Profitability Assessment in Long-Term Capacity Expansion Logic in AURORAxmp [6]

The purpose of this study is to analyze how ERCOT generation capacity evolves and what is the market outcomes with different levels of wind penetration and environmental regulation. In addition to the wind penetration level, however, there are other important inputs, such as projections for fuel prices, CO_2 prices, CAPEX, and demand during study periods. For this study, all of those market forecasts come from the base case scenario of EIA AEO 2012 [4], except for the demand forecast. ERCOT demand historically has shown a different growth rate from the U.S. average rate, so this study uses long term demand forecast released by ERCOT Planning Group [11]. Detailed modeling assumptions are described in the next section.

Chapter 3

Assumptions

3.1 Introduction

The study requires a lot of assumptions about future market variables to represent short-term and long-term dynamics of the ERCOT market: fuel prices, total and peak demand of electricity, capital cost improvements, transmission upgrades, carbon prices, etc. Furthermore, some of market rules should be appropriately simplified to reduce model complexity. This section explains data assumptions and market modeling simplification that this study takes.

First of all, the study period is from 2013 to 2040. However, the actual simulation ran from 2010 to 2043. That is, the first three and last three years are chopped off in order to eliminate possible erroneous beginning- and end-effects of simulations.

The following sections describe other assumptions in detail regarding existing units (Section 3.2), capital cost and renewable incentives (Section 3.3), fuel prices (Section 3.4), demand growth (Section 3.5), environmental regulation (Section 3.6), future of nuclear units (Section 3.7), wind production (Section 3.8), scarcity pricing (Section 3.9), and operating reserves (Section 3.10).

3.2 Existing Units

The existing resource list in ERCOT and their detailed information (heat rate, fuel type, minimum up-time or down-time, minimum and maximum capacity, etc.) are already constructed and included in AURORAxmp ERCOT model, which mostly come from *NERC Electric Supply and Demand Database* and *EIA Annual Electric Power Report*. Most recent unit status are also updated based on publicly available information from Capacity, Demand, and Reserve Report [14], System Planning Monthly Report [15], Mothballed Unit Status [13], MWDaily [21], etc, and described in Table 3.1.

Status	**Unit Name**	**Utility**	**Fuel**	**Capcity MW**	**Zone**	**Year Month**
Operating	Nacogdoches[1)]	Southern Company	Biomass	100	North	2012 Jun
Addition	Sandy Creek[2)]	TXU Power	Coal	925	North	2013 Jun
Addition	Panda Temple[3)]	Panda Energy	Gas	758	North	2014 Dec
Addition	Panda Sherman[4)]	Panda Energy	Gas	717	North	2015 Jan
Addition	Dear Park Energy Center	Calpine	Gas	260	Houston	2014 Jun
Addition	Channel Park Energy Center	Calpine	Gas	260	Houston	2014 Jun
Retirement	J.T.Deely	CPS	Coal	845	South	2018 Dec
Mothballed	AES Deepwater	AES Deepwater	Petcoke	142	Houston	2012 Oct
Mothballed	Sam Bertron#3	Texas GencoII	Petcoke	230	Houston	2012 Oct
Mothballed	Sam Bertron#4	Texas GencoII	Petcoke	230	Houston	2012 Oct

[1)] 20-year Power Purchase Agreement (PPA) with Austin Energy
[2)] PPA with LCRA
[3)] Financing completed and under construction
[4)] Financing on-going

Table 3.1: Recently Updated Resource Status in ERCOT

3.3 Capital Cost and Renewable Incentives

This study uses CAPEX assumptions from the EIA AEO 2011 base case [3]. AEO assumes that there will be technological improvement in generation sector and corresponding cost reduction in capital cost of all types of technology. Especially, the capital cost reductions of wind and solar generation are noticeable as shown in Figure 3.1.

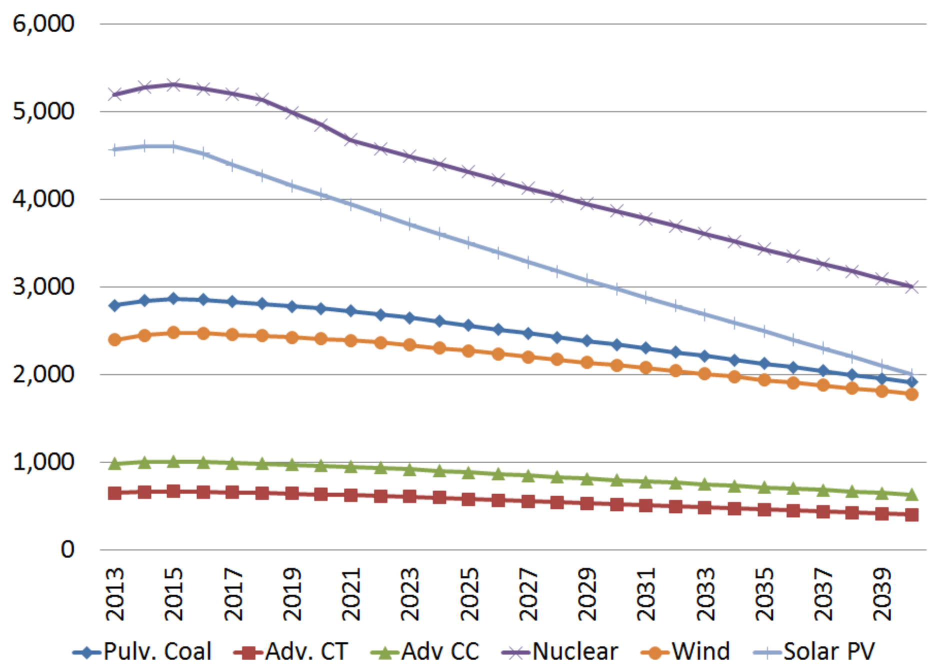


Figure 3.1: Capital Cost Assumptions [$\$/kW$] [3]

The study represents 30% Investment Tax Incentives when calculating CAPEXs of renewable resources like wind and solar. For example, ITC reduces capital cost of wind by 48.38 [2010 \$/kW] in 2010. PTC, however, is not considered in this study, so does not affect marginal cost calculation of renewable energy production.

PTC and RPS are major drivers of investment in renewable generation. However, the study does not model them explicitly. Instead, it assumes that different wind penetration levels (will be discussed at Section 3.8) result from different renewable incentives like PTC or RPS. The purpose of this study is to analyze the impact of different wind penetration levels on the future ERCOT market, and various wind levels are assumed to result from PTC, RPS, or any possible forms of renewable incentives. As a result, the study will help us to assess how much wind energy should be generated and what is the impact on the market when a desired wind penetration level is achieved.

3.4 Fuel Prices

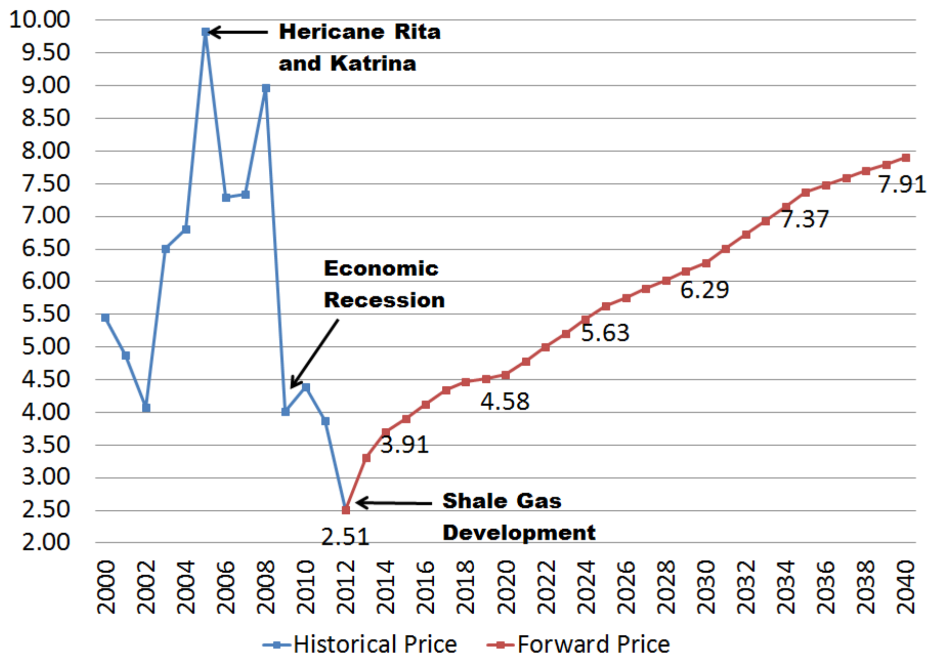


Figure 3.2: Historical and Forward Henry Hub Prices [2010$/*mmbtu*] [4]

Fuel (coal, natural gas, uranium, and oil) price projections in this study come from the EIA AEO 2012 base case [4]. All prices are converted to real 2010 dollars using EIA Consumer Price Index (CPI) estimation. However, since natural gas prices impacts most on the ERCOT market, the study uses the forward prices of Henry Hub from 2013 to 2017 that are actually traded in *IntercontinentalExchange* (ICE), in order to reflect a real gas market situation. Afterwards, EIA forecast for Henry Hub is used. Historical and projected Henry Hub prices are shown in Figure 3.2.

3.5 Demand Growth

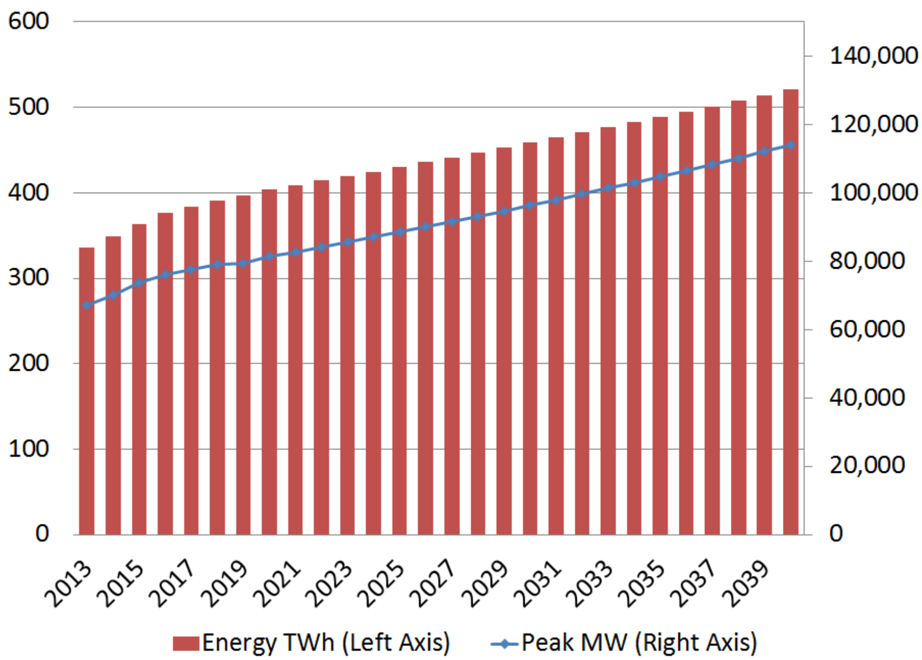


Figure 3.3: Peak and Annual Demand Forecast in ERCOT [11]

Taking into account economic and weather forecast of Texas, ERCOT reports its long term demand forecast up to 2020 in [11]. This study uses the same demand growth as in [11] from 2012 to 2020, and after that extrapolates the demand growth rate from 2021 to 2040 by fixing the 2020 growth rate. This fixed demand growth rate was decided considering population projection [23], energy efficiency, and demand response impacts [22] during this period. The graph and values for demand projection for the study is shown in Figure 3.3. It should be mentioned that different projection for future economy, technology, climate change, etc. could result in different demand growth. One of the assumptions of demand growth in this study is that historical population and GDP growth of Texas have been higher than the US average, and that population and GDP growth will continue this trend during the study period.

3.6 Environmental Regulation

Recently, U.S. Court overturned the Cross-State Air Pollution Rule (CSAPR), which was first announced in 2011. Even though Environmental Protection Agency (EPA) will revisit this later and announce a modified version of it, the resulting regulations are uncertain.

Not only CSAPR, but other environmental regulations also have a great deal of uncertainty regarding actual implementation. However, one thing can be conjectured is that whatever the format is, there will be a way to regulate environmental impacts of thermal generation that emits Green House Gas (GHG) and other pollutants (NO_X, SO_2, mercury, etc.). Therefore, this study includes GHG15 scenario of AEO 2012 [4] and assumes that this is a representative form of future environmental regulations imposing penalties to the emission produced by thermal units. GHG15 scenario imposes CO_2 price 15$\$/ton$ at 2013 and increases it by 5% every year by 2035.

3.7 Future of Nuclear Units

The Fukushima accident froze many of the current and future projects of nuclear units all around the world. For example, Germany has announced that it will shut down all nuclear plants by 2022, and a new nuclear project in ERCOT was also canceled after the disaster. Current nuclear plants in Texas - capacity of 5,133 MW - will be operating until at least to 2027 or 2033 according to their current licenses, but for continuous operation in following years, they should apply for the re-extension of their licenses. This study assumes that current licenses will not be extended, and the units will be retired when current licenses are expired. However, the model is allowed to add a new nuclear unit if the long term investment logic concludes it is favorable to do so.

3.8 Wind Generation

3.8.1 Wind Production Model

This study uses wind profiles which are analyzed by EPIS, a developer of AURORAxmp. The source of that data comes from the Western and Eastern Wind Datasets produced by the National Renewable Energy Laboratory (NREL) [6]. Based on geographic topology and typical wind patterns, ERCOT West Zone is divided into 15 regions, and South Zone is divided into 2 regions. Each region has a representative 168-hour (24 hour $\times$ 7 days) wind profile (capacity factor) at each month. The wind model assumes that within a month, a weekly profile would repeat to model total hours in the month. By expanding this to 12 month of a year, it can represent 8760 hours of wind profile in a region.

The modeled wind profile is applied to a total capacity of a wind farm in a region in order to calculate wind production at each hour. Therefore, if you increase wind capacity in one region, corresponding wind generation also increases linearly. This may not be true for actual generation from future wind farms. However, since this study focuses on long-term impacts of increasing wind capacity on the ERCOT market, it is assumed that uncertainties regarding the wind modeling methodology in this study would be minimized for a long-term perspective.

3.8.2 Wind Penetration Level

Given the general assumptions described so far, this study generates four different scenarios depending on different wind penetration levels - base case (10%), 20%, 27%, and 33%. Wind penetration level is defined in energy values, using the following equation:

$$\text{Wind Penetration Level}\,(\%) \;=\; \frac{\text{Wind Energy produced in a year}\,[TWh]}{\text{Year Total Energy}\,[TWh]} \tag{3.1}$$

For given wind penetration levels (10%, 20%, 27%, and 33%) and estimated capacity factor (30%), total wind capacity required to meet that penetration level is calculated based on energy forecast in 2030 (459 TWh). For example, for 10% wind case, 45.9 TWh wind energy should be produced in 2030. Taking into account 30% wind capacity factor, required total capacity to achieve the target is approximately 17,466 MW based on the equation below:

$$\text{Required Wind Capacity}\,[MW] \;=\; \frac{\text{Wind Energy}\,[MWh]}{\text{Capacity Factor}\,[\%] \times 8760[hours]} \tag{3.2}$$

Then the required wind capacity minus 2012 wind capacity is divided by a number of years between 2013 to 2030, so that the same amount of wind addition is calculated and added every year from 2013 to 2030. Although, as historically observed, actual wind capacity addition will be more variable than this perfectly linear increase, it approximates a consistent increase of wind capacity up to a target level. The resulting wind penetration level is shown in Figure 3.4. As wind capacity increases, wind energy production and its penetration level increases as well, but after achieving the target, a smaller number of new wind capacity is added economically comparing to the fixed amount added before.

3.9 Scarcity Pricing

Even though this study does not analyze future reserve margin or resource adequacy issue, modeling scarcity price is also important in this study, since it determines not only infra-marginal profits of peaking units, but also that of non-peaking

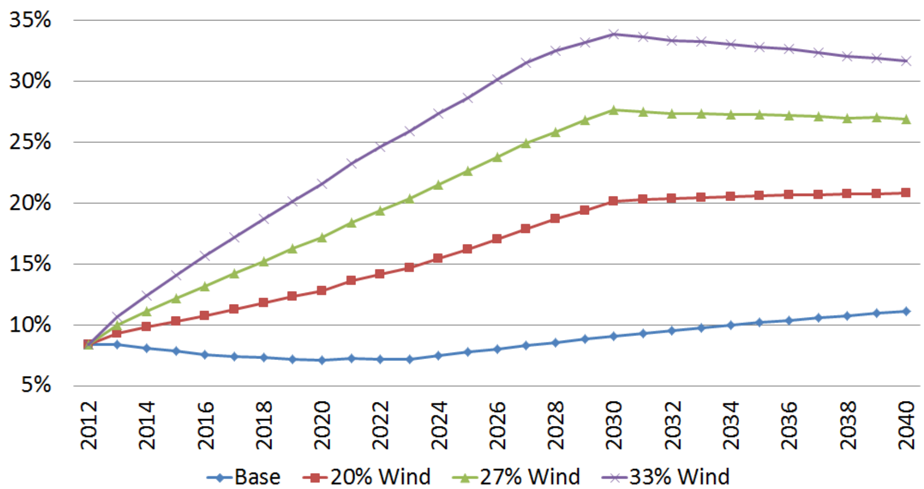


Figure 3.4: Resulting Wind Energy Penetration by Scenarios

units. The model allows a user to specify a price offer-cap, which in this study is 4,500 $\$/MWh$ - the current price offer-cap. Whenever supply cannot match demand, a market price is set to this value. However, this model does not exactly match actual price formation in ERCOT, since small market participants can make offers at "scarcity price" even in the absence of scarcity. Moreover, over the study horizon, there are likely to be several modifications to the rules for price formation, in order to resolve the resource adequacy issue in ERCOT.

3.10 Operating Reserves

ERCOT has three different ancillary services in the real operation: regulation up/down, responsive reserves, and non-spinning reserves. Each ancillary service has different roles and obiligation, but the main purpose of them is to make the system cope with net load variability and unexpected forced outages of transmission lines and units. Detailed requirements of the ERCOT ancillary services are described in [9].

The model approximates operational reserve requirements as procuring 6.5%

of demand at each hour from a set of units at the top of the resource stack. That is, it is assumed that the top 6.5% of total capacity of most expensive units in that hour provides operational reserves. The model does not separate operational reserves into three different ancillary services that ERCOT currently has.

Chapter 4

Simulation Results

4.1 Introduction

Five different scenarios: Base Case, Base Case without CO_2 Price (No CO_2 Case), 20% Wind, 27% Wind, 33% Wind are analyzed to see the impacts of imposing CO_2 price and increasing wind penetration on the ERCOT market outcomes: capacity expansion, generation by fuel type, market price, system costs, and amount of emission.

Base Case has no fixed addition of wind, but Long-Term Capacity Expansion Logic adds them if they are profitable to be built. Four different wind penetration scenarios have a fixed amount of wind addition to satisfy each wind penetration target. Base Case and all wind cases have CO_2 prices which matches with EIA GHG15 prices (15 $\$/ton$ at 2013 and increase by 5% every year by 2035), while Base Case without CO_2 price does not have any penalty for emitting CO_2.

All scenarios have different paths of generation expansion, but have share similar trends in common. Natural gas units continue to be a major portion of ERCOT capacity, and its contribution becomes greater every year in every scenario. Low gas price projection, high fuel efficiency, high operational flexibility, and less emission have more gas units committed, dispatched, and built than coal units.

The first section of this chapter (Section 4.2) will discuss the impacts of CO_2 price on Capacity Expansion (Section 4.2.1), Generation by Fuel Type (Section 4.2.2), Market Price & Costs (Section 4.2.3) , and Amount of Emissions (Section 4.2.4). Next, in section 4.3, the impacts of increasing wind penetration will be investigated on the same perspectives, from section 4.3.1 to section 4.3.4.

4.2 Impacts of Environmental Regulation

4.2.1 Capacity Expansion

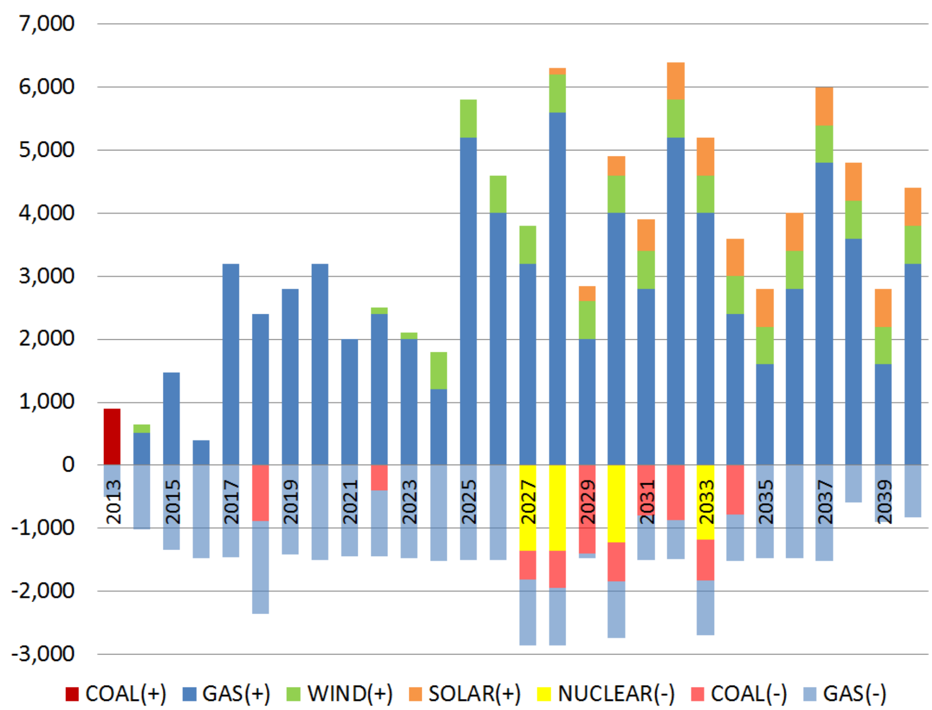


Figure 4.1: Capacity Expansion (+: Addition, −: Retirement) MW of Base Case

Fitures 4.1 and 4.2 shows estimated capacity expansion every year of base case and base case without CO_2 price, respectively. Positive values mean capacity addition, while negative ones represent capacity retirement in a year. The major difference between two base case is that, by having CO_2 penalties, we see more coal retirement and renewable (solar and wind) additions. Table 4.1 shows the total amount of addition and retirement during the study period between 2013 and 2040.

The retirement of coal units in the Base Case is $9,390$ MW, while only 800

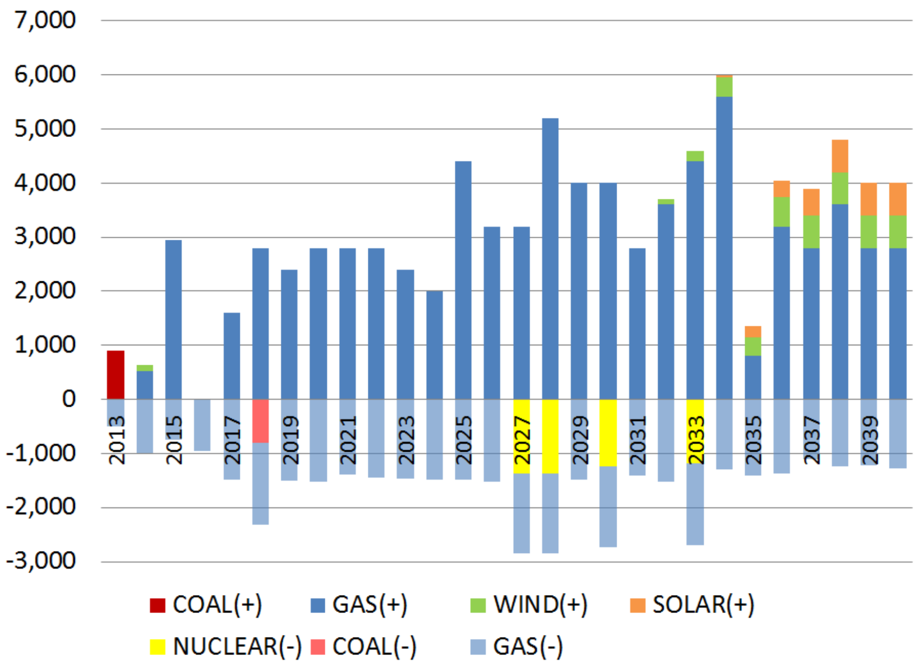


Figure 4.2: Capacity Expansion (+: Addition, $-$: Retirement) MW of Base Case without CO_2 Regulation

MW retirement is observed in the base case without CO_2 price. 800 MW retirement is recently announced one (J.T.Deely at CPS in 2018, see Table 3.1). That is, in the base case without CO_2 price, there is no economic retirement of coal units and no economic addition of coal.

The amount of coal retirement in the Base Case, $9,390$ MW, is almost half of the current coal capacity, 19 GW, in ERCOT. The capacity deficit from 9 GW coal retirement is replaced by 4 GW of solar PV, 6 GW of wind, and 4 GW of Net Gas Addition.

Two base cases also show different renewable resource expansions. (Note that for both base cases, there is no fixed addition of wind nor solar except the ones under construction. Furthermore, Production Tax Credit is not represented in this study) Economic addition of wind starts at 2022 in the base case, and at 2033 in the base case without CO_2 price. Solar PV starts to be added at 2028, while at 2035 for the base

Capacity [MW] Addition	COAL (+)	CCGT (+)	SOLAR (+)	WIND (+)
Base	900	77,595	6,550	10,520
Base w/o CO_2	900	79,470	2,850	4,070
Capacity [MW] Retirement	**COAL (−)**	**CCGT & ST (−)**	**OCGT (−)**	**NET GAS**
Base	-9,390	-23,039	-8,311	46,246
Base w/o CO_2	-800	-29,120	-8,285	42,065

Table 4.1: Total Addition and Retirement of Two Base Cases

case without CO_2 price. That is, wind starts to be added into the ERCOT system economically 11 years earlier, and solar PV is added 7 years earlier in the base case compared to the base case with no CO_2 price. This is because CO_2 penalties increase power prices, equivalently future revenue streams of renewable resources, so justify economic addition of wind and solar PV earlier than the base case without CO_2 price. Total amounts of wind and solar additions of two base cases are also different and shown at Table 4.1.

In conclusion, whether there is regulation on CO_2 emission or not, natural gas units are going to be a major portion of capacity portfolio in the ERCOT market. Having CO_2 penalties, however, increase the amount of net addition of gas units by 10% (or 4 GW) due to the massive retirement (50% of current capacity) of coal units. Furthermore, CO_2 penalties will justify investment of wind and solar PV 11 years and 7 years earlier, respectively, resulting in more renewable penetration.

4.2.2 Energy Production

Optimal Power Flow (OPF) logic determines the least cost way to serve a given demand subject to each unit's capacity, transmission limits, and bus voltage limits. In this study, a resource is modeled as offering a price to the market based on the marginal cost of their next MW generation. Marginal cost is expressed as,

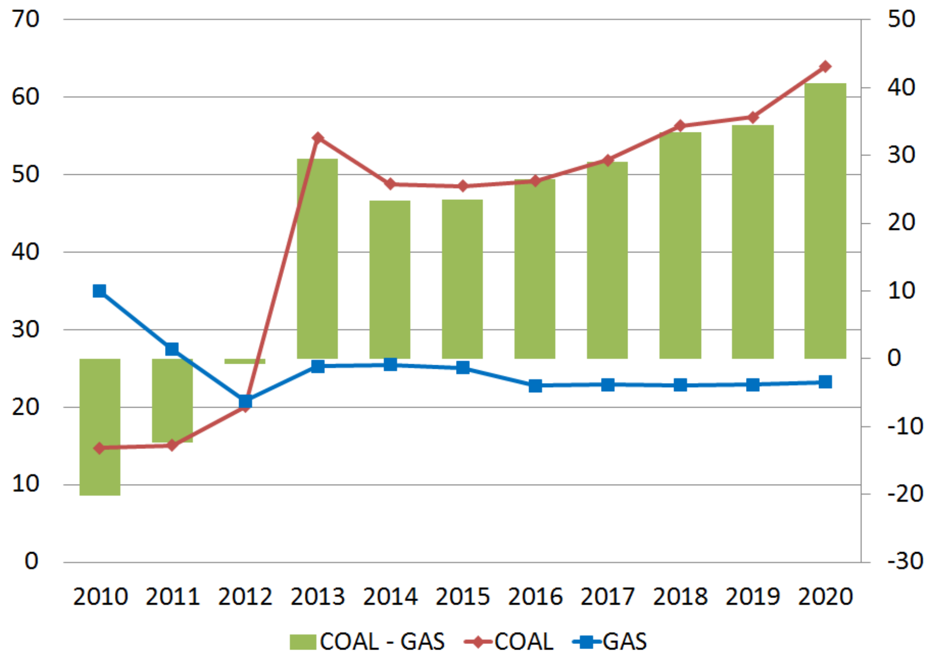


Figure 4.3: Marginal Cost [$\$/MWh$] of Coal and Gas Units (Left Axis), the difference (Right Axis) - Base Case including CO_2

$$
\begin{aligned}
\text{Marginal Cost}\,(\$/MWh) = &\ \text{Incremental Heat Rate}\,(btu/kWh) \times \text{Fuel Price}\,(\$/mmbtu) \\
&+ \text{VOM}\,(\$/MWh) \\
&+ \text{Emission Rate}\,(ton/MWh) \times \text{Emission Price}\,(\$/ton) \\
&+ \text{Bidding Factor}\,(\$/MWh)
\end{aligned}
\tag{4.1}
$$

As mentioned in section 3.9, such competitive offers may not always match actual offers.

With a negligible amount of emissions rate or no emission price and with no bidding factor, most of the marginal cost consists of variable fuel cost. However, high emissions cost can have a greater contribution to marginal cost calculation than variable fuel cost, if the emission price or rate is considerable.

Coal units have considerably higher emissions rates than natural gas units.

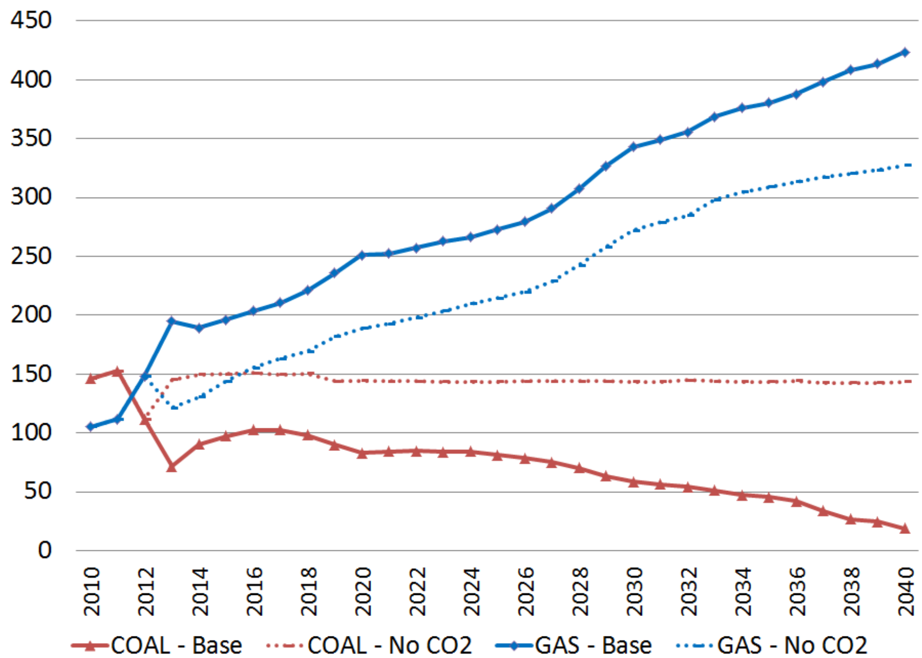


Figure 4.4: Energy Production TWh of Coal and Gas Units for Two Base Cases

This study found that GHG15 assumption from AEO 2012 [4] increases marginal cost of coal units significantly as shown in Figure 4.3 starting 2013 when CO_2 prices are imposed.

As observed in the previous section, CO_2 prices worsen coal units' profitability and retire almost half of the current coal units by 2040 in the Base Case, while the base case without CO_2 price has no retirement of coal units. However, CO_2 prices have impacts not only on capacity expansion (especially coal retirement), but also on coal and gas generation and capacity factors, which are shown in Figures 4.4, 4.5, and 4.6, respectively.

Figure 4.4 shows coal (red lines) and gas (blue lines) units' generation from 2013 to 2040 for two base cases (solid line for with CO_2 price, dashed line for without CO_2 price). CO_2 regulation increases the marginal cost of coal units greater than the gas units (Figure 4.3), reduces total coal generation (from the red dashed line to the

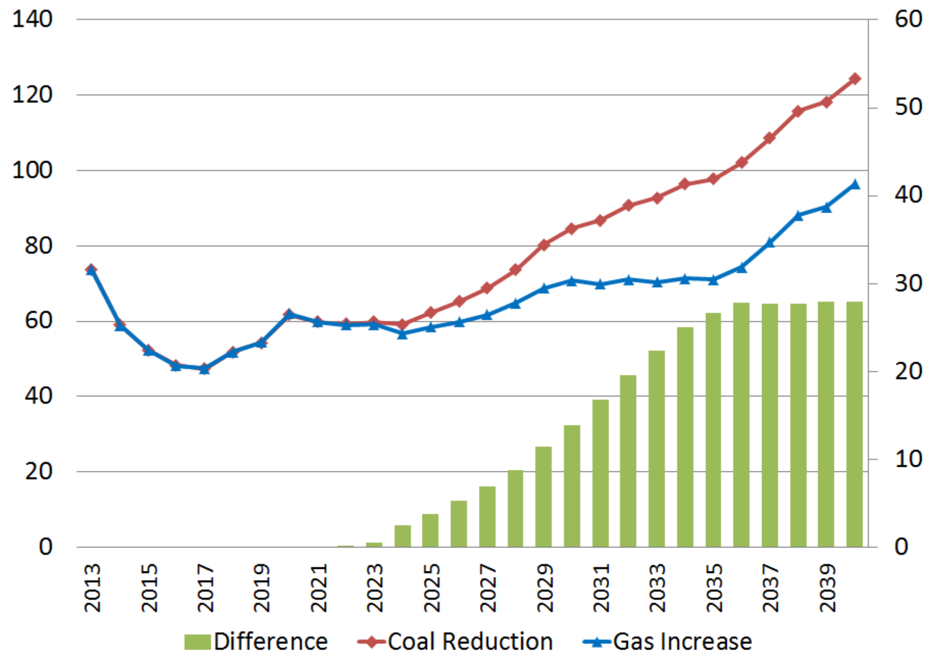


Figure 4.5: Amounts of coal reduction, gas increase, and the difference in TWh by imposing CO_2 (from Figure 4.4)

red solid line in Figure 4.4), but increase total gas generation (from the blue dashed line to the blue solid line in Figure 4.4). The amount of coal generation reduced from the base case without CO_2 price to the base case is almost identical to the amount of gas generation increased from 2013 to 2022 (Figure 4.5), but afterwards, reduction in coal generation is not fully replaced by an increase in gas generation. This is because wind and solar PV start to be added economically at 2022 and 2028 respectively, and contribute energy production needed to fill the reduction of coal generation.

Increase of marginal cost of coal units due to CO_2 prices has significant impacts on coal units' capacity factor as well, shown in Figure 4.6. Before imposing CO_2 price, coal unit's capacity factor remains same around 87%. After CO_2 regulation imposed, capacity factor of coal units dropped to 42% in 2013, and it falls down even further to 20% in 2040. Therefore, reduction of coal generation is attributed to reduction of the capacity factor and of the capacity of coal units in the system.

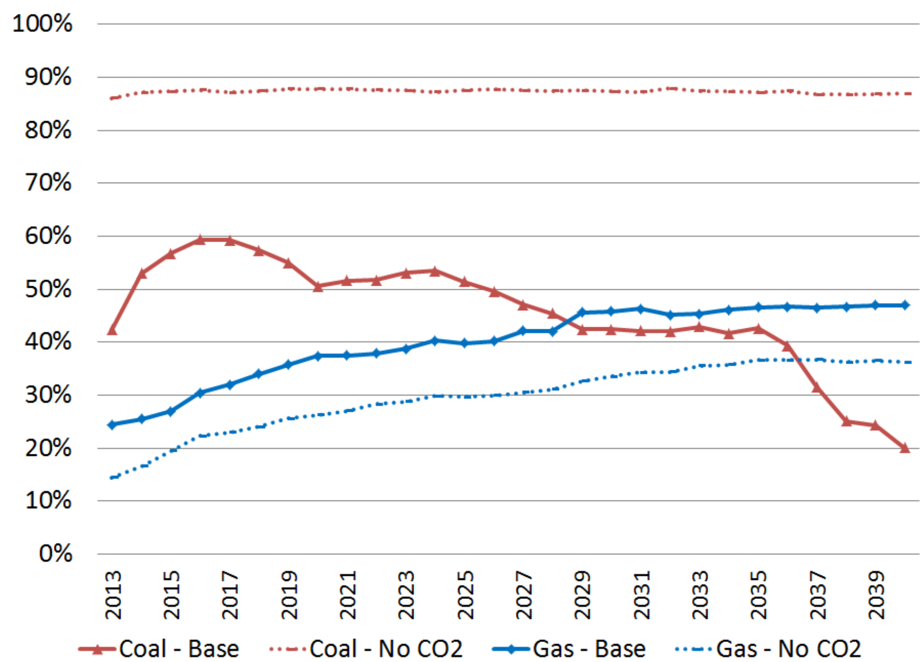


Figure 4.6: Capacity Factor % of Coal and Gas Units for Two Base Cases

Average capacity factor of gas units is increased by 10% for all study years shown in Figure 4.6. Increased capacity factor and net capacity (4 GW in Table 4.1) means that in the Base Case, there is 66 TWh more energy produced from gas units every year in average than the generation from gas units in the base case without CO_2 price.

4.2.3 Market Price & System Cost

CO_2 penalties increase marginal cost of all thermal generation commensurate with amount of CO_2 emission. As a result, they increase power prices. Figure 4.7 shows ERCOT North Zone On- and Off-Peak Prices of two Base Cases. On-Peak time is defined as the hours between 7AM to 10PM (hour ending) which are 16 hours, while

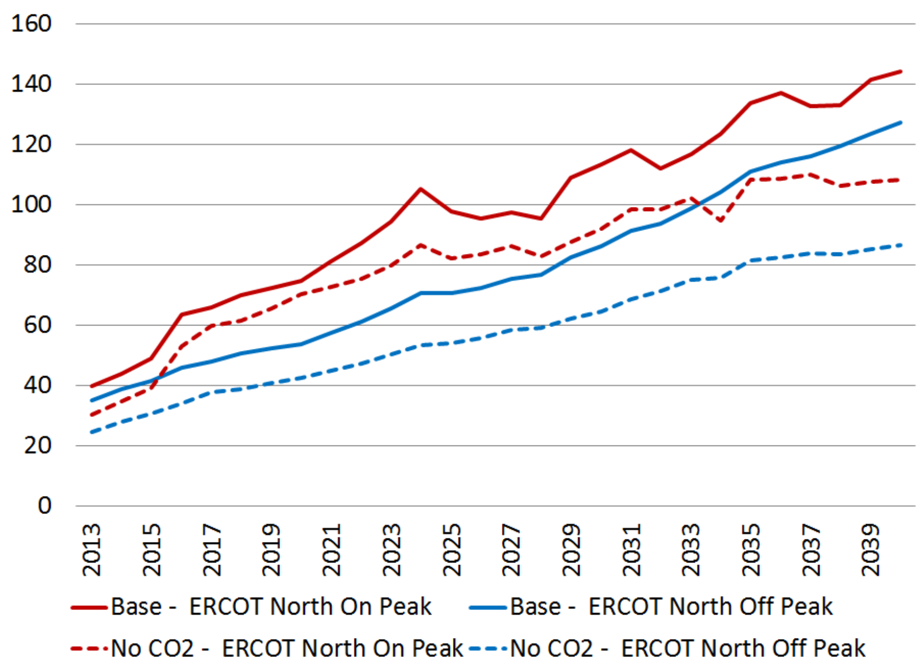


Figure 4.7: ERCOT North Zone On- and Off-Peak Prices [$\$/MWh$] for Two Base Cases

Off-Peak time is between 11PM to 6AM which are 8 hours[1]. As conjectured, Base case including CO_2 penalties has higher prices on both on- and off-peak hours for the entire study years. This is because as shown in Equation 4.1, increasing an emission cost [$\$/ton$] increases a marginal cost of a thermal unit, so it will increase its offer price into the market. One interesting observation from Figure 4.7 is that for many years, Off-Peak price of Base Case is even higher than On-Peak price of no CO_2 case.

Table 4.2 describes the values in Figure 4.7, and Table 4.3 shows the price difference between two base cases in the years of 2015, 2020, 2025, 2030, 2035, and 2040. Note that the difference in off-peak Prices between the base case and the base case without CO_2 price is greater than the on-peak price difference as shown in Table 4.3. This is because CO_2 price has higher impacts on coal units, which are mostly

[1]Note that ERCOT standard on-peak product is 7AM to 10PM from Monday to Friday, and off-peak product is 11PM to 6AM from Monday to Friday plus all hours in weekends

used to serve base load generation during off-peak time.

Year	Base On Peak	Base Off Peak	Base Average	No CO_2 On Peak	No CO_2 Off Peak	No CO_2 Average
2015	49.00	41.50	45.25	39.23	30.58	34.91
2020	74.70	53.70	64.20	70.34	42.53	56.44
2025	98.00	70.74	84.37	82.28	54.14	68.21
2030	113.34	86.40	99.87	92.16	64.69	78.42
2035	133.97	111.18	122.57	108.37	81.42	94.90
2040	144.37	127.27	135.82	108.52	86.74	97.63

Table 4.2: ERCOT North Zone Price [$\$/MWh$] of Two Base Cases

Year	On-Peak Price Difference [$\$/MWh$]	Off-Peak Price Difference [$\$/MWh$]	CO_2 Price [$\$/ton$]
2015	9.77	10.92	18.35
2020	4.36	11.17	25.84
2025	15.72	16.60	36.44
2030	21.18	21.71	52.03
2035	25.60	29.76	74.86
2040	35.85	40.53	0

Table 4.3: Difference in On- and Off-Peak Prices b/w Two Base Cases and CO_2 Prices

The total production costs including emission costs in the ERCOT system are also increased as CO_2 prices are imposed as shown in Table 4.4. The increase ranges from 45% to 49%. That is, the ERCOT system spends at least 45% more money to serve same amount of demand, if the level of CO_2 regulation from EIA GHG15 case is imposed[2]. Whether benefits from CO_2 regulation could justify this amount of additional costs in the system should be deferred to further studies, but the amount of emission reduction will be discussed at the following section 4.2.4.

[2]Note that the only difference between two base cases is whether imposing CO_2 prices: the base case has 15 $\$/ton$ of CO_2 price in 2013 and increases it by 3 % every year by 2035, while the base case without CO_2 price has zero CO_2 price for all years.

Year	Base Case Million \$	Base Case w/o CO_2 Price Million \$	Increase %	CO_2 Price \$/*ton*
2015	12,439	8,422	47.7	18.35
2020	19,092	13,147	45.2	25.84
2025	27,533	18,924	45.5	36.44
2030	40,461	27,781	45.6	52.03
2035	57,503	39,213	46.6	74.86
2040	70,894	47,485	49.3	0

Table 4.4: Total Generation Costs in the ERCOT system

The increases in the total generation costs between two base cases remain between 45% to 49%, while CO_2 prices consistently increase from 2013 to 2035 by 5% every year. This is because retirement and diminished capacity factors of coal units observed at previous sections, diminish the increase in the total production cost of the ERCOT system.

4.2.4 Amount of Emissions

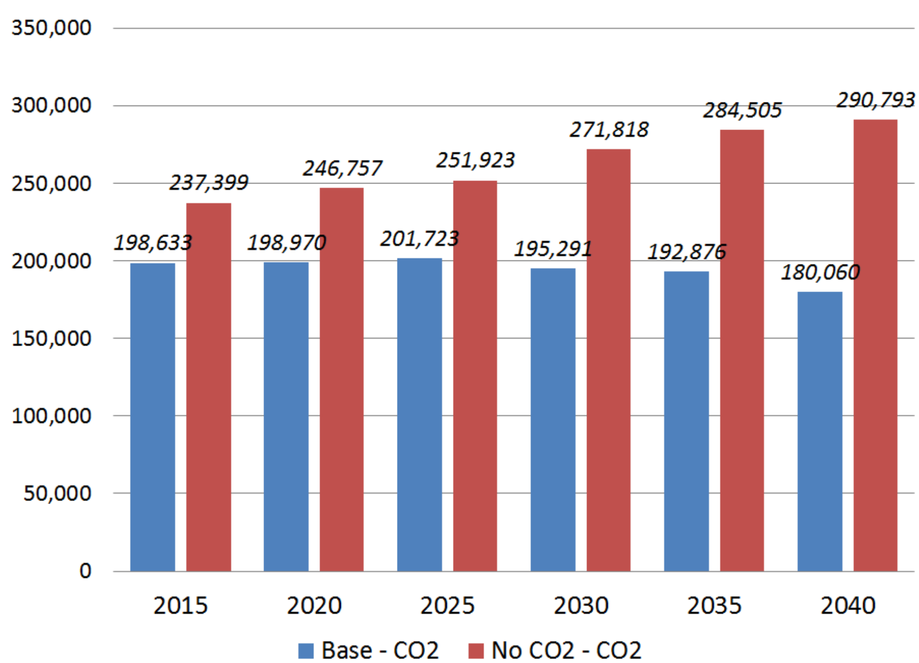


Figure 4.8: Amount of CO_2 Emissions [*thousand ton*] of Two Base Cases

Year	CO_2 Reduction Rate	NO_X Reduction Rate	SO_2 Reduction Rate
2015	16.3 %	20.7 %	38.7 %
2020	19.4 %	29.0 %	48.5 %
2025	19.9 %	31.5 %	50.1 %
2030	28.2 %	46.7 %	70.7 %
2035	32.2 %	54.0 %	80.9 %
2040	38.1 %	69.4 %	94.2 %
Total	25.4 %	39.4 %	61.5 %
From 2010	17.0 %	70.6 %	94.8 %

Table 4.5: Reduction Rate of Three Emission Types after imposing CO_2 penalties

This section describes how many emissions are reduced by imposing CO_2 prices. The amounts of emissions of Base Cases with and without CO_2 price for three different types are assessed here: CO_2 in Figure 4.8, NO_X in Figure 4.9, and SO_2 in Figure 4.10. By retiring coal units, reducing generation from *surviving* coal units, and introducing renewable generation earlier, CO_2 regulation reduces all types of emission as shown in Figures 4.8, 4.9, and 4.10.

Table 4.5 summarizes the results of emission reduction. **Total** row in the table shows the reduction (%) in total accumulated amount of emission from 2013 to 2040 after imposing CO_2 prices. The accumulated emissions reduce by 25.4 % for CO_2, 39.4 % for NO_X, and 61.5 % for SO_2. During these periods, the total amounts of emission savings are, 1.9 billion tons of CO_2, 1.4 million tons of NO_X, and 7.4 million tons of SO_2.

From 2010 row shows the reduction rate at 2040 comparing to the emission level in 2010, when there is no penalty for emitting CO_2. The amount of emission in 2040 reduces by 17.0 % for CO_2, 70.6 % for NO_X, and 94.8 % for SO_2 comparing to the emission level at 2010. That is, in 2040, the ERCOT system emits less 36.8 million tons of CO_2, 88.8 thousand tons of NO_X, and 448.7 thousand tons of SO_2

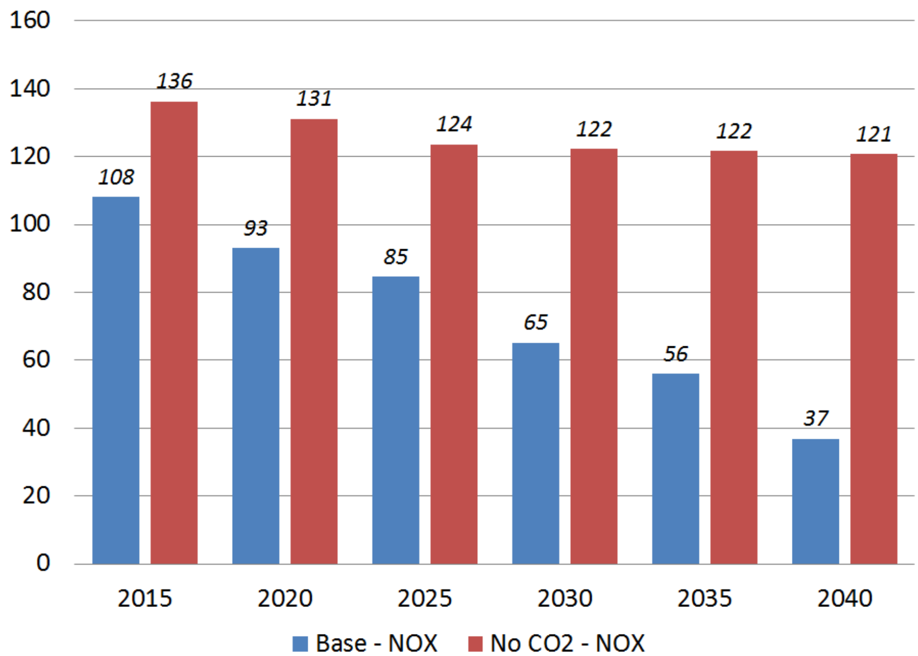


Figure 4.9: Amount of NO_X Emissions [*thousand ton*] of Two Base Cases

comparing to the 2010 emissions, while the total system demand increases from 319 TWh to 521 TWh (60.5 %).

Emission reduction in NO_X and SO_2 is more prominent than that in CO_2. This is because CO_2 penalties induce significant amount of coal retirement and reduction in generation from coal units, and NO_X and SO_2 are mostly emitted by coal units, while gas units still emit CO_2 even though the amount is much less than that from coal units. Therefore, higher reduction rate is observed in NO_X and SO_2 emission than in CO_2 emission.

This study does not quantify the economic benefits of the reduction of three types of emission. Further studies are required to answer whether those benefits are big enough for a society to justify the increased cost of total generation described at the previous section. However, this study provides fundamental information for further studies on economic benefits and costs of CO_2 penalties by quantifying both

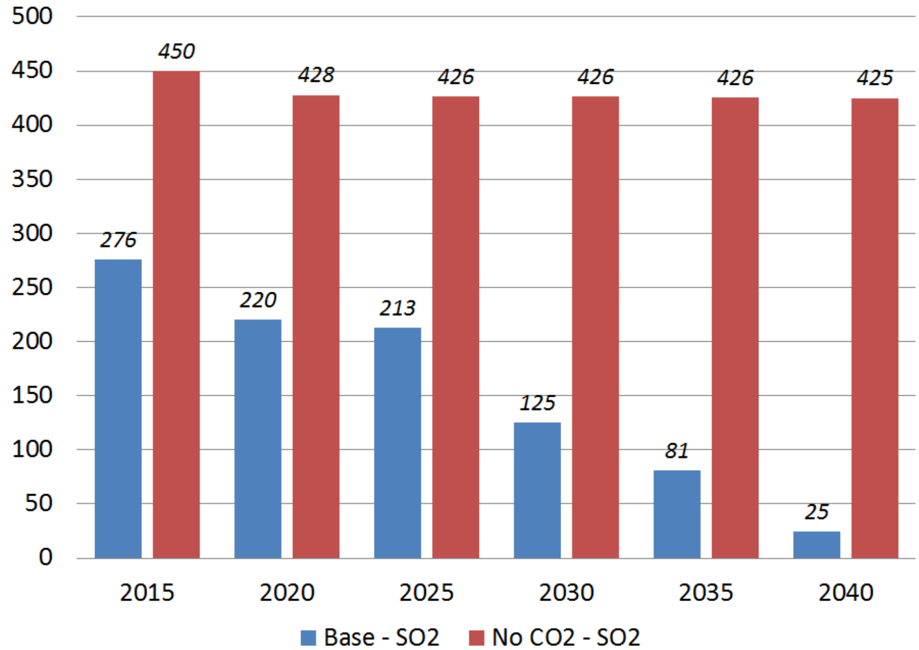


Figure 4.10: Amount of SO_2 Emissions [*thousand ton*] of Two Base Cases

the amount of generation cost increased and emission reduced.

4.3 Impacts of Wind Penetration

So far, the thesis has discussed the impacts of environmental regulation on capacity expansion, energy production, market price, system cost, and amount of emission in ERCOT from a long-term perspective. This section investigates the impacts of different wind penetration level on the same aspects from Section 4.3.1 to Section 4.3.4. Note that in this thesis, penetration is defined in terms of energy, unless otherwise specified.

4.3.1 Capacity Expansion

Figure 3.4 in the previous chapter shows wind penetration levels every year for different scenarios – base case (10%), 20%, 27%, and 33% wind penetration cases. As

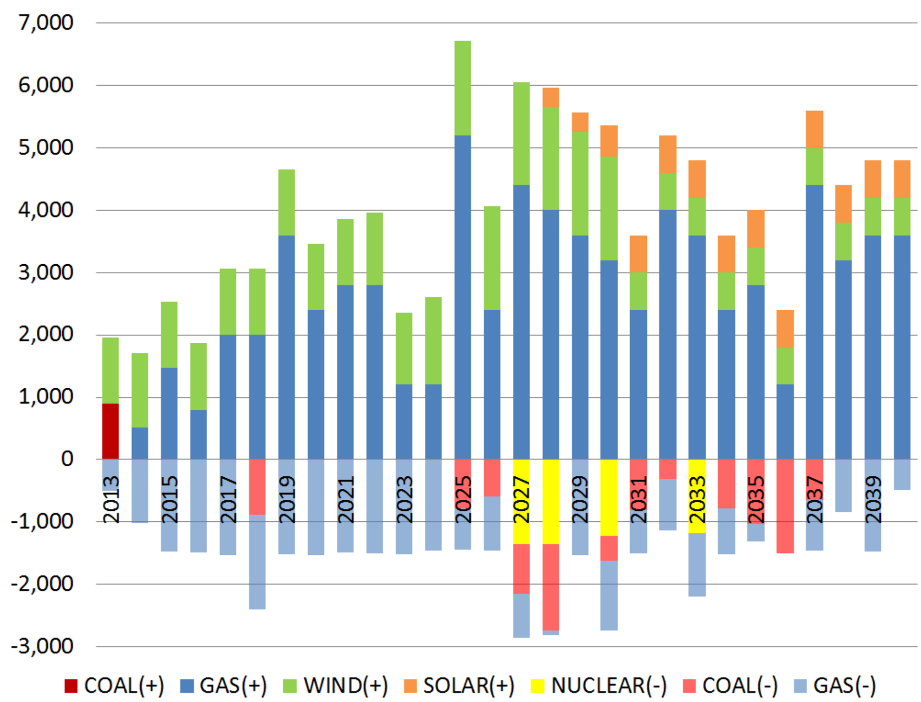


Figure 4.11: Capacity Expansion (+: Addition, −: Retirement) MW of 20% Wind from 2013 to 2040

more wind resources are integrated into the system, wind generation would replace energy production from thermal generation. However, the amount of reduction in thermal generation due to increase in wind generation is not linear, since it depends on wind patten and variability, fuel price, net load, etc. This section tries to quantify the amount of capacity addition and retirement of different fuel types, varying wind penetration levels, in the ERCOT deregulated environment.

Figures 4.11, 4.12, and 4.13 graphically show capacity expansion of 20%, 27%, and 33% wind penetration case, respectively. Positive values represent capacity addition, while negative means retirement. Each year, different amount of capacity addition and retirement by different fuel types result from Long-Term Optimization Logic in AURORAxmp, which decides economic addition and retirement of different technologies.

Capacity $[MW]$	COAL (+)	CCGT (+)	SOLAR (+)	WIND (+)
Base (10%)	900	77,595	6,550	10,520
20% Wind	900	74,795	7,100	29,254
27% Wind	900	70,795	7,150	41,884
33% Wind	900	70,795	6,700	54,300
Capacity $[MW]$	COAL $(-)$	CCGT & ST $(-)$	OCGT $(-)$	NET GAS Addition
Base	-9,390	-23,039	-8,311	46,246
20% Wind	-11,307	-20,412	-8,292	46,091
27% Wind	-11,276	-16,891	-8,119	45,785
33% Wind	-12,157	-18,700	-7,999	44,096

Table 4.6: Total Amount of Addition and Retirement of Base(10%), 20%, 27%, and 33% Wind Penetration Case (+: Addition, $-$: Retirement)

Table 4.6 summarizes capacity expansion of different wind penetration level, showing the total sum of capacity addition and retirement of different fuel types during the study period from 2013 to 2040. As more wind resources are added into the system, generally more coal units are retired, and less amount of net gas capacity is added. Even though wind capacity increases dramatically from 10 GW to 54 GW, the amount of coal retirement and net gas addition does not change that much.

Moving from 10% to 20% wind penetration, there are 20 GW more wind addition, 2 GW more coal retirement, but net gas addition remains almost same at 46 GW.

Moving from 20% to 27% wind penetration, there are 12 GW more wind addition, but no major changes in coal retirement and net gas addition. That is, when total amount of wind capacity addition from 2013 to 2040 increases from 10 GW to 41 GW, net gas addition remains unchanged at 46 GW.

Moving from 27% to 33%, there are 12 GW more wind addition, 1 GW more coal retirement, approximately 2 GW less amount of net gas addition. Therefore,

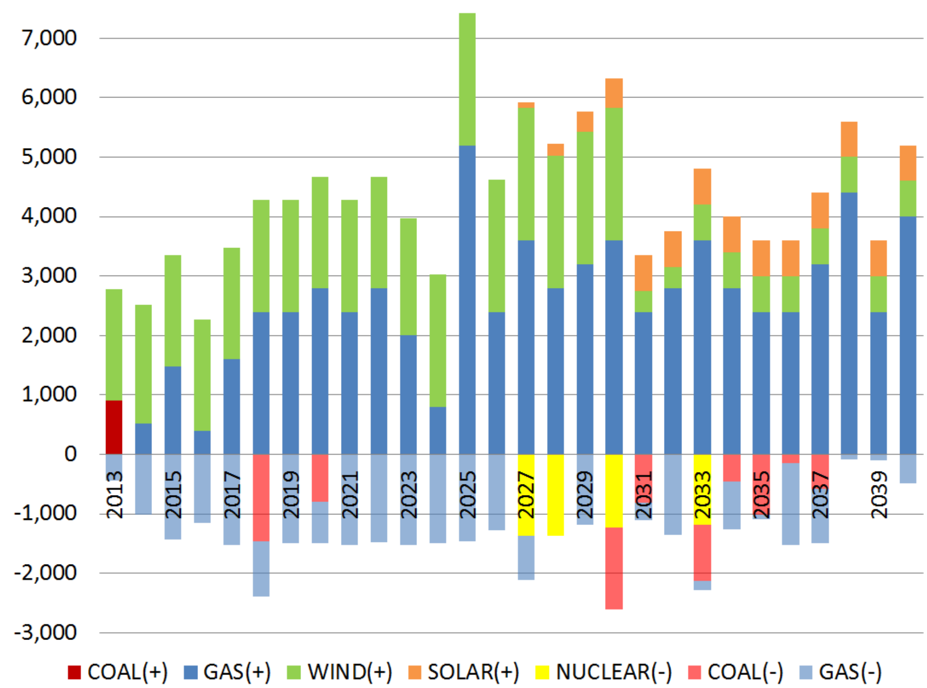


Figure 4.12: Capacity Expansion (+: Addition, $-$: Retirement) MW of 27% Wind from 2013 to 2040

in general, as wind capacity increases, more coal units are retired and less gas units are added, but the system needs dramatic increase in wind capacity to see noticeable changes in coal and gas capacity expansion.

Consequently, 44 GW of wind addition substitutes 3 GW of coal capacity and 2 GW of gas capacity. Assumes that ELCC[3] of coal and gas units are 100%, the ELCC of wind farm in this study is $5/44 = 11.4$ %. When there is high wind penetration, however, this depends on how correlated the wind farms are with each other. ELCC of different wind penetration levels are summarized in Table 4.7.

Less amount of changes in capacity expansion of thermal units than those of wind resources implies that there would be greater changes in generation and capacity

[3]Effective Load Carrying Capability. In [18], ELCC is used to denote *Capacity Value*

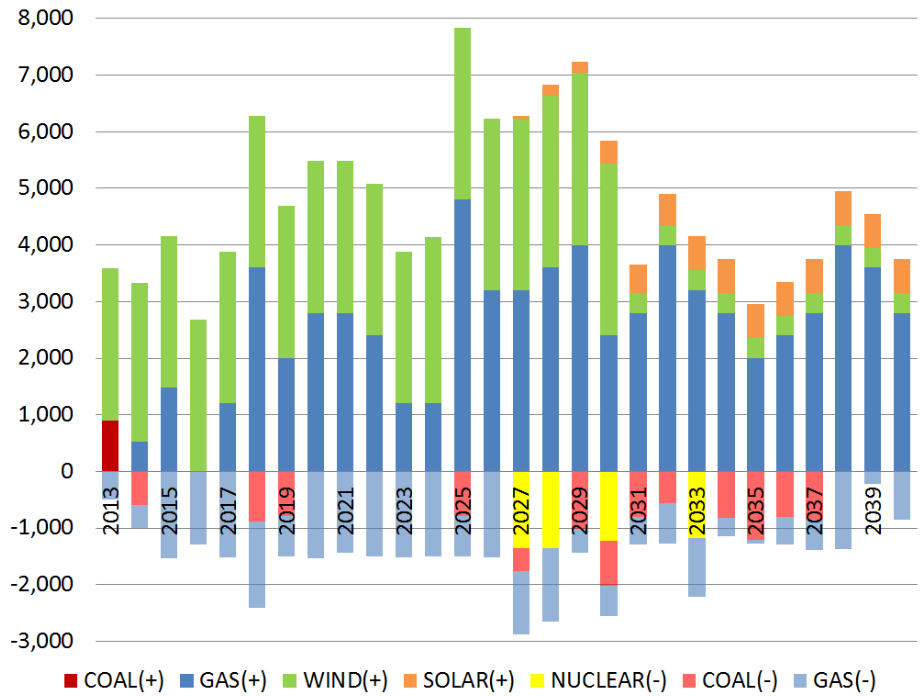


Figure 4.13: Capacity Expansion (+: Addition, −: Retirement) MW of 33% Wind from 2013 to 2040

Wind Penetration	20% Wind	27% Wind	33% Wind
ELCC	15 %	13.6 %	11.4 %

Table 4.7: ELCC for Different Wind Penetration Levels

factor for thermal generation under high wind penetration, which is discussed in the following section 4.3.2.

4.3.2 Energy Production

This section discusses changes in coal and gas generation by different wind penetration levels and assesses how wind penetration affects them. Figures 4.14 and 4.15 show coal and gas generation by different wind penetration from 2013 to 2040, respectively. General trends on both Figures can also be found in Figure 4.4: decrease in coal generation and increase in gas generation which are mainly caused by CO_2

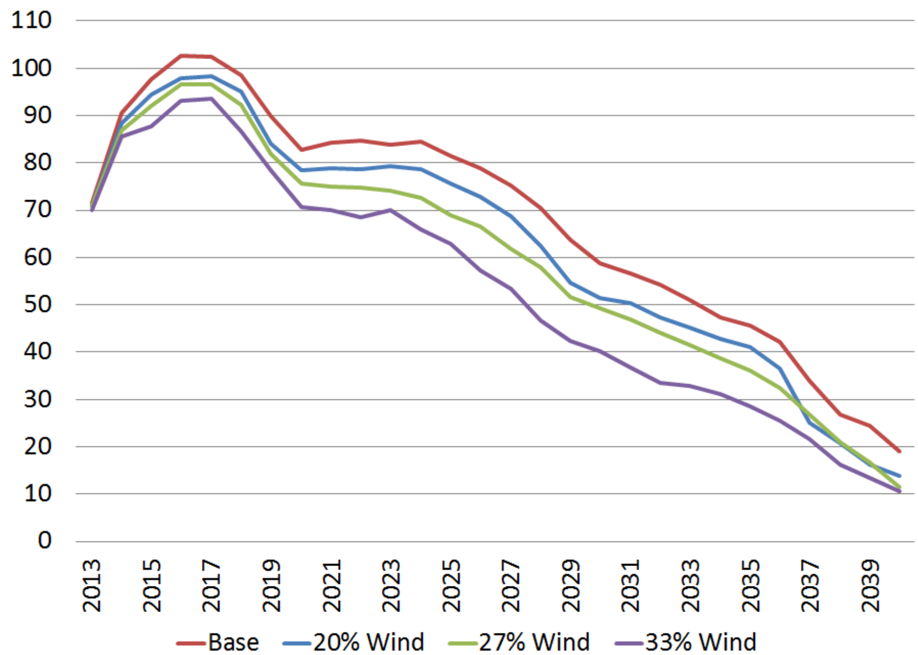


Figure 4.14: Coal Generation [TWh] of Different Wind Penetration Cases from 2013 to 2040

penalties.

Generally, as wind penetration increases, both coal and gas generation decrease as shown Figures 4.14 and 4.15 (moving from a red solid line to a purple solid line). It is obvious that as more wind resources are added, more amount of generation from coal and gas units are substituted with wind energy, since marginal cost of wind generation is much lower (close to zero not considering tax credits) than those of gas and coal units.

Tables 4.8 and 4.9 show total amount of coal and gas generation by different wind penetration levels during three different periods (2013 to 2020, 2021 to 2030, and 2031 to 2040) They also show reduction in generation at one penetration level of wind from the previous wind penetration level. For example, the total coal generation between 2013 to 2020 is 736.1 TWh at the 10 % wind case, while it is 707.5 TWh at

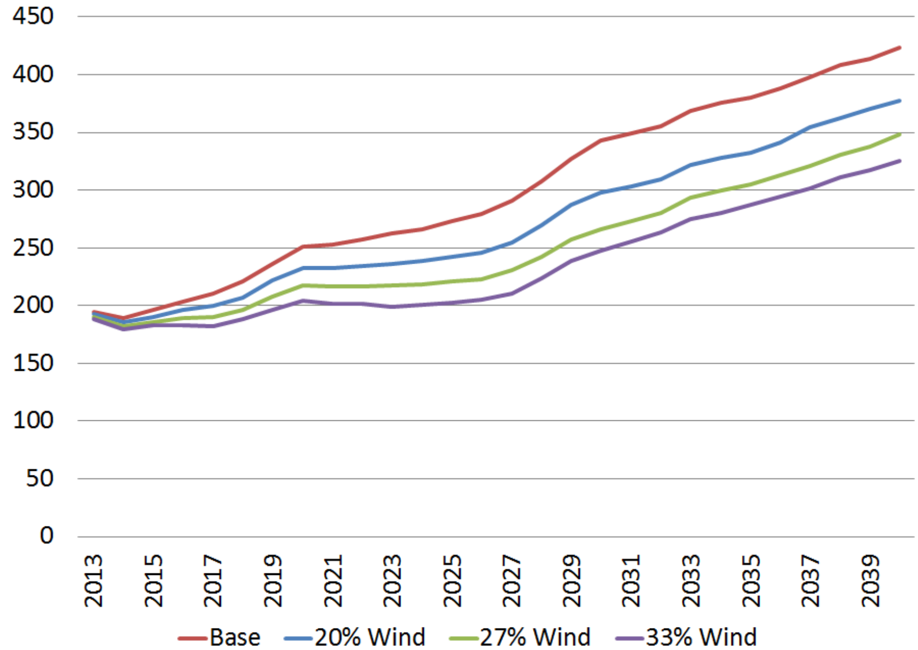


Figure 4.15: Gas Generation $[TWh]$ of Different Wind Penetration Cases from 2013 to 2040

the 20 % wind case, which results in 3.9 % reduction shown in Table 4.8.

10% to 20% wind transition has the greatest impact on coal and gas generation, as it does on capacity expansion. One thing to be noticed from Table 4.8 is that the transition from 27% to 33% of wind penetration has higher reduction rate on coal generation for all three periods than for the transition from 20% to 27%. From this observation, it is expected that after a certain point of wind penetration between 27% and 33%, there will be a steeper drop in coal generation than before.

However, the reduction in gas generation by increasing wind penetration, gradually and consistently reduce shown in Table 4.9. That is, the marginal changes of gas generation reduces as wind penetration increases. Another observation from the table is that reduction rates during $2021-2030$ and $2031-2040$ periods are almost consistent within the same wind penetration level, while the reduction rate in coal generation varies by time periods within the same wind penetration level.

Period	Base(10%) [TWh]	20% Wind [TWh]	27% Wind [TWh]	33% Wind [TWh]
$2013-2020$	736.1	707.5	692.5	665.6
Reduction	–	3.9 %	2.1 %	3.9 %
$2021-2030$	766.0	701.4	652.9	577.4
Reduction	–	8.4 %	6.9 %	11.6 %
$2031-2040$	401.5	339.0	315.4	250.1
Reduction	–	15.6 %	7.0 %	20.7 %

Table 4.8: Amount of Coal Generation and Reduction Rate by Scenarios

Period	Base(10%) [TWh]	20% Wind [TWh]	27% Wind [TWh]	33% Wind [TWh]
$2013-2020$	1,704	1,626	1,560	1,506
Reduction	–	4.6 %	4.0 %	3.5 %
$2021-2030$	2,860	2,540	2,310	2,131
Reduction	–	11.2 %	9.0 %	7.8 %
$2031-2040$	3,862	3,401	3,102	2,912
Reduction	–	11.9 %	8.8 %	6.1 %

Table 4.9: Amount of Gas Generation and Reduction Rate by Scenarios

By comparing wind penetration impacts on capacity (discussed at the previous section) and generation of coal and gas units, it can be inferred that increasing wind penetration has higher impacts on generation than on capacity. For example, transitionning from 10% to 20% and from 20% to 27% of wind penetration has little impacts on net gas addition (46 GW), while 11% and 9% reduction in gas generation at the same transition of wind penetration.

4.3.3 Market Price & System Cost

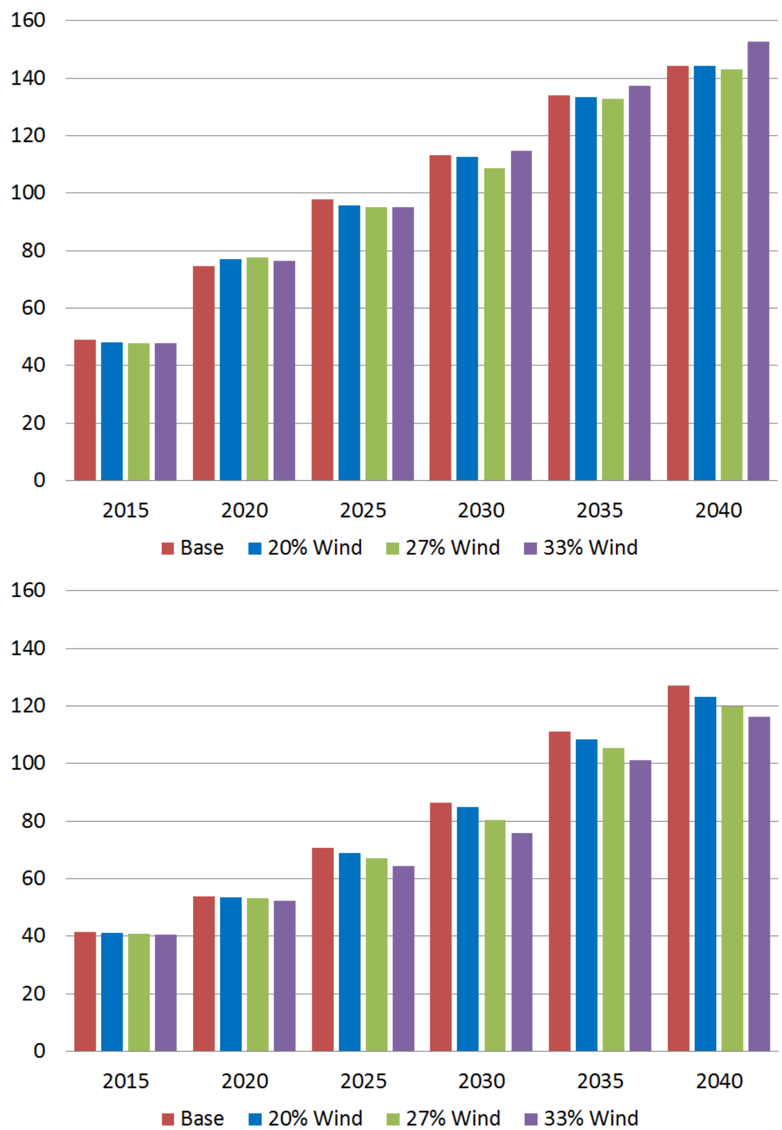


Figure 4.16: On-Peak(top) and Off-Peak(bottom) Price of ERCOT North Hub by Different Wind Penetration

Since wind resources produce energy that would replace generation from thermal units and have close to zero marginal costs, it is expected that market prices would be reduced as the system has higher wind penetration. Figure 4.16 shows on- and off-peak prices of ERCOT North hub at the years of 2015, 2020, 2025, 2030, 2035, and 2040. Tables 4.10 and 4.11 delineate the corresponding values. In the figure, off-peak prices clearly show this trend that the price decreases as wind penetration increases. This is because of a typical diurnal pattern of the Texas wind profile: wind blows more during off-peak times (11PM to 6AM Hour Ending, 8 Hours) than during on-peak times (7AM to 10PM Hour Ending, 16 Hours). Therefore, there is more wind generation during off-peak times than during on-peak times at the same level of wind penetration, and price reduction by increasing wind penetration is more prominent during off-peak times.

Year	Base(10%)	20% Wind	27% Wind	33% Wind
2015	49.00	48.20	47.78	47.88
2020	74.70	77.12	77.55	76.41
2025	98.00	95.68	95.07	95.25
2030	113.34	112.70	108.73	114.82
2035	133.97	133.57	132.85	137.41
2040	144.37	144.40	143.10	152.72

Table 4.10: ERCOT North Hub On-Peak Prices by Scenarios

Year	Base(10%)	20% Wind	27% Wind	33% Wind
2015	41.50	41.11	40.79	40.53
2020	53.70	53.55	53.31	52.27
2025	70.74	68.93	67.24	64.45
2030	86.40	84.84	80.45	76.00
2035	111.18	108.53	105.55	101.09
2040	127.27	123.07	119.96	116.23

Table 4.11: ERCOT North Hub Off-Peak Prices by Scenarios

However, on-peak prices show a different trend as off-peak prices do. By increasing wind penetration from 10% to 20%, on-peak prices of ERCOT North hub does not change much. By increasing wind penetration from 20% to 27%, market prices reduces, but the slope is not as much noticeable as observed in off-peak price reduction.

Increasing wind penetration from 27% to 33% shows a reverse trend to off-peak price one, as shown in Figure 4.16 and Tables 4.10 and 4.11. That is, 33% wind penetration has higher on-peak prices of North hub than 27% wind penetration does. It is estimated that after some point of wind penetration between 27% and 33%, the system commits and dispatches more expensive but flexible units (gas units), while de-commits coal units to cope with net load (load minus wind generation) variability (hourly in this study), canceling the effect of higher wind penetration on the reduction of electricity prices.

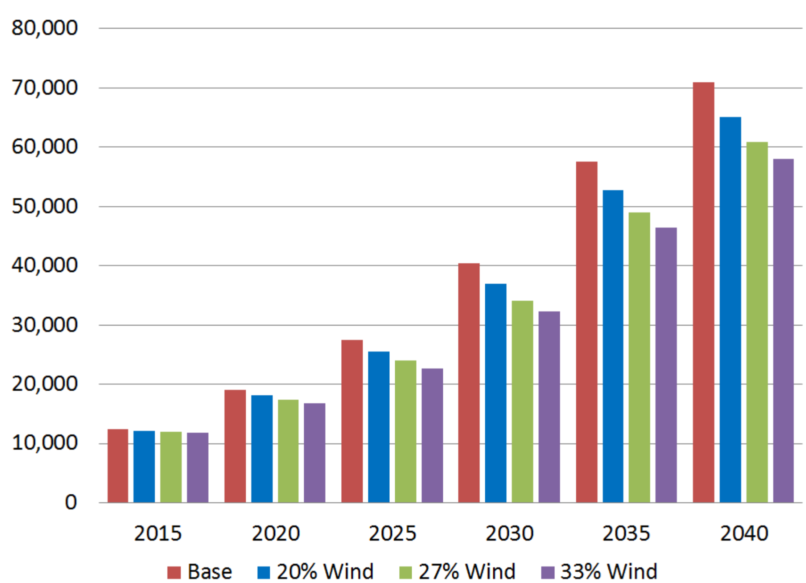


Figure 4.17: Total Generation Cost [*million* \$] in ERCOT by Wind Penetration Level

In the previous section 4.3.2, we also observed that coal generation has a higher reduction rate when wind penetration transitions from 27% to 33% than the transition in lower levels of wind penetration. This phenomena should be scrutinized further in future studies to assess the true cost of increasing wind penetration. After exceeding a certain penetration level of wind, as observed above, wind would not reduce market prices, but increase them.

Figure 4.17 shows the sum of generation cost per year of all resources in ERCOT to serve forecasted demand in different wind penetration levels. It is clearly observed that total generation cost reduces as wind penetration increases, since zero production cost wind generation substitutes a part of thermal generation.

4.3.4 Amount of Emissions

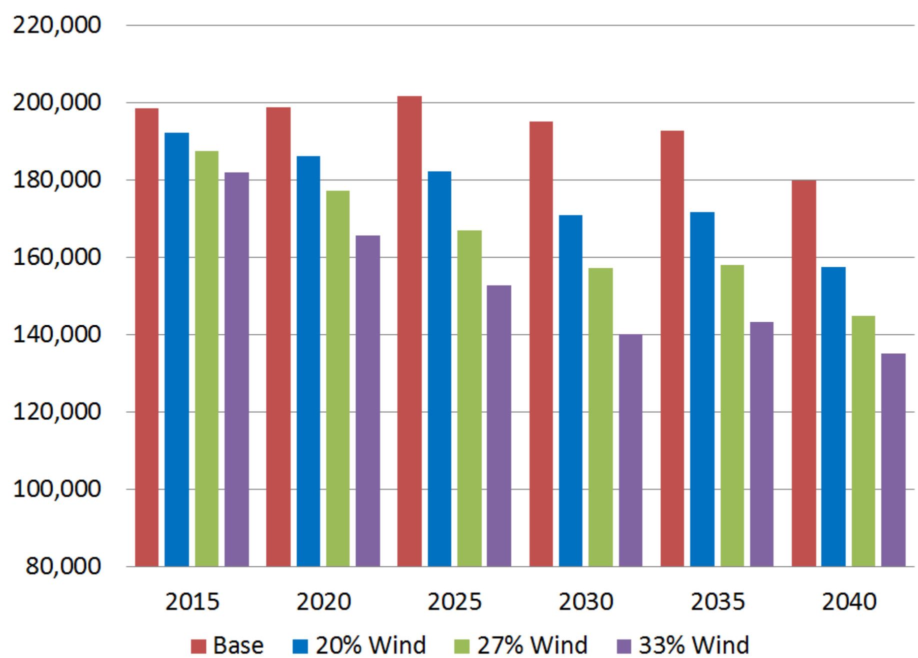


Figure 4.18: Amount of CO_2 Emission [*thousand ton*] by Wind Penetration Level

As more wind resources are added into the system, it is expected that there would be less emission. This section describes the impact of different wind penetration levels on the emission of CO_2, NO_X, and SO_2, which are drawn in Figures 4.18, 4.19,

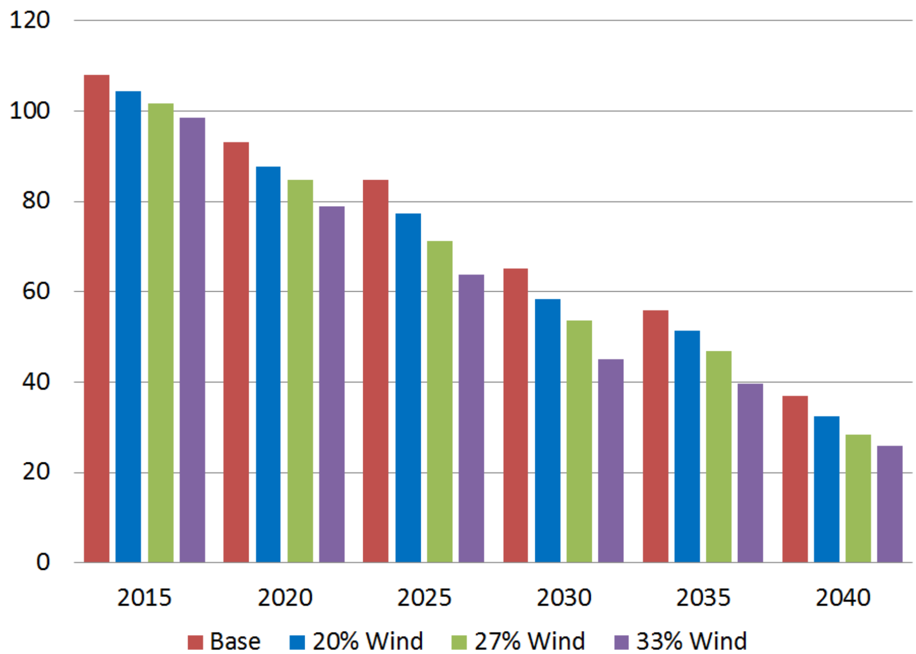


Figure 4.19: Amount of NO_X Emission [*thousand ton*] by Wind Penetration Level

and 4.20 respectively. It is clearly shown on the figures and Table 4.12 that more wind resources reduce all three types of emission further.

Emission Type	Reduction in Total Emissions From 10% Wind to 33% Wind
CO_2	21.0 %
NO_X	20.1 %
SO_2	20.2 %

Table 4.12: Reduction in the Total Amount of Emissions by types for the 33% Wind Case comparing to the Base Case (10% Wind)

Note that the major drivers of emission reduction are the retirement of coal units and reduced capacity factor of survived coal units. This is because coal units has higher contribution to all three types of emission than gas units do as shown in Table 4.13. The emission rates of a gas unit is almost half for CO_2, a quarter for NO_X, and one over a thousand for SO_2 comparing to the emission rates of a coal

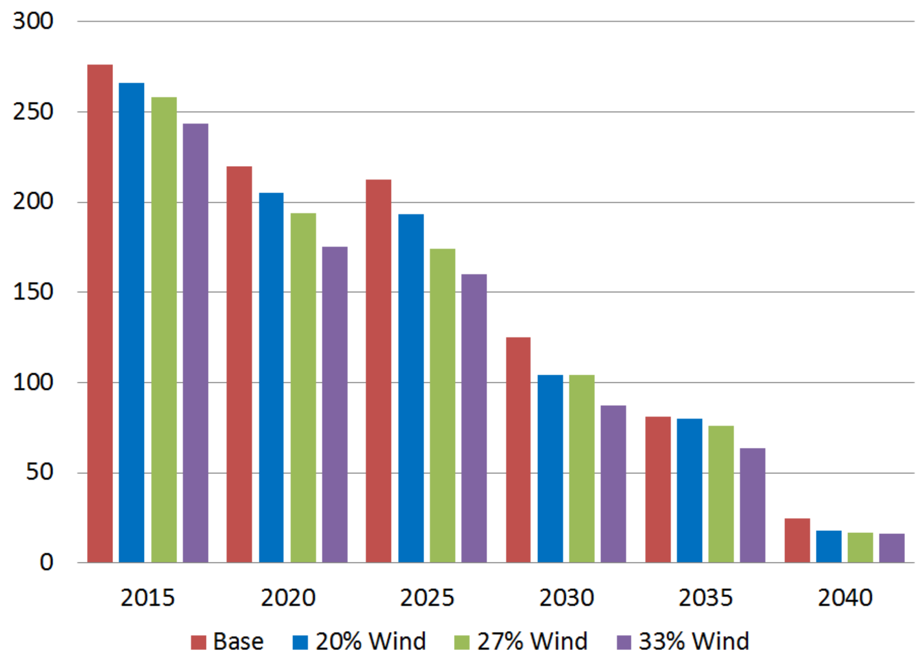


Figure 4.20: Amount of SO_2 Emission [*thousand ton*] by Wind Penetration Level

unit.

Fuel Type & Emission Rate	CO_2 [$lb/mmbtu$]	NO_X [$lb/mmbtu$]	SO_2 [$lb/mmbtu$]
Coal	212	0.1500	0.5600
CCGT	119	0.0370	0.0007

Table 4.13: Emission Rate of Typical Coal and CCGT unit in ERCOT [6]

Increasing wind penetration reduces all three types – CO_2, NO_X, and SO_2 – of emission. Furthermore, it generally reduces power price and generation costs as well, as described in the previous section. However, it needs further studies to answer whether the benefits of increasing wind penetration – reduction of GHG emission, power price, and generation cost – could justify costs associated with it. The costs will be mostly tax credits and incentives, because in order to achieve wind penetration levels specified in this study, there should be tax-related incentives accordingly to encourage further wind development than economic based investment for wind resources in a deregulated electricity market.

Chapter 5

Conclusion and Future Work

5.1 Conclusion

This thesis assesses the impacts of environmental regulation and wind penetration levels on capacity expansion, generation, market price, system cost, and amount of emissions in the ERCOT market, using a commercially available market simulator, AURORAxmp. The model incorporates short-term and long-term market dynamics to properly model real time operation of power system and long term investment decision in a deregulated environment.

The study period is from 2013 to 2040. The basic assumptions in this study, such as fuel prices, CO_2 prices, and capital costs originate from EIA AEO 2011 [3] and AEP 2012 [4]. In [4], the *Henry Hub* gas price is forecasted to be 3.91 $\$/mmbtu$ in 2015 and 7.91 $\$/mmbtu$ in 2040 as shown in Figure 3.2. The price of CO_2 is assumed to be 15 $\$/ton$ in 2013 and increase by 5% every year by 2035.

The peak and total demand comes from the ERCOT long-term demand forecast [11]. The 2040 peak and average demands are forecasted to be 96 GW and 453 TWh with 1.9 % and 1.6% of Compound Annual Growth Rates (CAGR) from 2013, respectively.

The study runs five scenarios: the base case with CO_2 price, the base case without CO_2 price, 20% wind penetration case, 27% wind penetration case, and 33% wind penetration case[1]. The following can be concluded:

[1] All wind cases includes CO_2 prices

1. Whether there are CO_2 prices or not, natural gas units will be a major portion of capacity portfolio in the ERCOT market.

2. Almost 50% of the current coal units will be retired, while there will be 10% or 4 GW of increase in net gas addition by imposing CO_2 prices.

3. CO_2 prices also reduce generation and capacity factor of coal units, but increase those of gas units. However, the impact is greater on coal units than on gas units.

4. CO_2 prices increase both on- and off-peak prices in ERCOT. Price increase in off-peak hours is more prominent than in on-peak hours due to reduction in coal capacity and generation.

5. Imposing CO_2 prices also reduces amount of CO_2, NO_X, and SO_2 emission, but NO_X and SO_2 reduction are more noticeable than CO_2 reduction, since NO_X and SO_2 are mostly emitted by coal units whose capacity and generation are dramatically reduced by CO_2 regulation.

6. Increasing wind penetration has marginal impacts on thermal capacity expansion: moving from 10% to 33% wind penetration requires 44 GW more wind addition, but 3 GW more coal retirement, and 2 GW less net gas addition, resulting in 11.4 % of the ELCC of wind power during the study period[2].

7. Wind penetration has higher impacts on generation than on capacity. For example, transitionning from 10% to 20% and from 20% to 27% of wind penetration has little impacts on net gas addition which remains around 46 GW, but resulting in 11% and 9% reduction in gas generation respectively.

[2]from 2013 to 2040

8. Generally on- and off-peak prices reduce as wind penetration increases, and the reduction is more prominent in off-peak prices. There are some variation on the on-peak price trend: moving from 27% to 33% of wind penetration increases on-peak price.

9. Increasing wind penetration also reduces all three types $-$ CO_2, NO_X, and SO_2 of emission.

5.2 Future Work

This thesis raises several further studies as follows:

1. Quantifying the economic benefits of CO_2 regulation (significant reduction in all types of emission) to see whether they justify increases in generation costs and power prices

2. Assessing the benefits (reduction in emission, system cost, and power price) and costs (tax incentives to encourage wind development) of increasing wind penetration

3. Comparing resource expansion results in this study with approximated results from augmented screen curve analysis

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Vita

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